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MAINTAIN, ENHANCE AND IMPROVE RELIABILITY OF CALIFORNIA'S ELECTRIC SYSTEM UNDER RESTRUCTURING

APPENDIX - XIV

Pushing Capacity Payments Forward: Agent-Based Simulation of an Available Capacity Market

PIER FINAL PROJECT REPORT

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Prepared By:

Lawrence Berkeley National Laboratory

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Pushing Capacity Payments Forward

Agent-Based Simulation of an Available Capacity Market

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REPORT SUMMARY

This study demonstrates that agent-based simulation is a useful tool for analyzing existing and proposed design features of electricity markets. The study documents not only how this technology functions, but how it can be used. Experiments using computer-based agents were used to simulate the effects of capacity markets on energy markets, and the project takes a particularly close look at the proposed Available Capacity (ACAP) market of the California independent system operator (CA-ISO). These agents play the role of market participants by formulating bids to maximize their profits. They exercise their skills under a number of scenarios of demand and levels and types of forward contracting for capacity in a simple market without congestion. This report also describes the skeleton of a potentially valuable program for addressing basic problems of investment and market power in the electricity industry. The program optimizes returns for both producers and consumers and involves the interactions between (1) system reliability, (2) market power, (3) generation capacity, and (4) electrical energy. These four aspects of the electric power system form the fundamental basis for economic interactions, and they also are inextricably linked to system operations.

Results & Findings

Study results indicate that the proposed ACAP market of the CA-ISO Market Design 2002 (MD02) will result in heightened payments for capacity, because this market will not remove capacity payments from the energy market. Subsequent experiments with forward capacity contracts that are supplemented with energy strike prices show that spot energy price spikes—which are the signals for new capacity—can be removed from the spot energy markets. Once removed, they can be pushed into the forward market where participants are better able to respond appropriately. This effect has the combined advantages of reducing overall costs to the consumer and securing returns for supply- and demand-side investments.

The study's simulations and analysis of capacity markets were done on a simple and closed system. The real world is much more complex. Further work is needed to understand the implications of more detailed aspects of capacity markets, such as forced outages, congestion, and new entrants.

Challenges & Objectives

This report was developed primarily to apply agent-based simulation to design issues in electricity markets and to explore alternative solutions for managing competitive markets and investment incentives. Since applying agent-based simulation to electricity market design is a groundbreaking exercise, it is valuable to document these initial experiences and results. This report also will be of interest to any person who studies or participates in electricity markets and is particularly interested in the relationship between spot energy prices, capacity markets, and incentives for investment in the power system. The subject of capacity markets is tightly coupled with the idea of managing market power. So, while the focus of these experiments was limited to

the very short term, the larger subject of long-term planning and the balance between generation and demand response is addressed as part of the discussion on forward contracting for capacity.

The work described here contributes to a better understanding of electricity market behavior in the abstract and, potentially, in real life. Simulating decisions, whether how to bid or how to change market rules, before implementing them can have enormous benefits. The unintended consequences of such decisions can be very costly. As it continues to mature, market simulation will be one of many tools that will bring stability and more secure benefits to all those who are participating in the transformation of electric power systems.

Applications, Values & Use

Further studies of this type are expected in the coming years. As the industry learns better how to use this technology, the technology will be further driven to new heights of achievement and application. Two factors that could extend simulation benefits are more realistic market data and longer time frames. The most important contribution that this report and its supporting technology can make to the debate over regulatory policy and industry reform is to help stakeholders better understand each other and the implications of decisions.

EPRI Perspective

EPRI has pioneered developing and applying agent-based simulation for the study of decision-making associated with electricity markets. While using computers to achieve this is relatively new, others have used people in similar experiments for some time. In fact, the recent Nobel Prize in Economics was awarded to the pioneers of this type of investigation, which is called Experimental Economics. EPRI's agent-based efforts build on this experience directly, replacing people as participants with computer programs that make the same decisions. EPRI's aim is to continue following developments in Experimental Economics and to create agents that can mimic human decision-making processes, with a goal of mimicking and even predicting actual market behavior.

Approach

The project team's goal was to document agent-based simulation as a tool for studying CA-ISO's proposed ACAP market. The team devised market clearing mechanisms and agent decision-making procedures to form bids in this market environment. Simulations were run over numerous scenarios of demand and forward contracting for a stylized California system. Team members designed scenarios to elicit competitive and non-competitive market behavior to better understand the source and reasoning for price spikes and their relation to incentives for investment.

Keywords

Electricity markets
Agent-based simulation
Economics
Market power
Competition
Investment

ABSTRACT

This report describes experiments using computer-based agents to simulate the effects of capacity markets on energy markets. The study looks particularly at the proposed Available Capacity (ACAP) market of the California Independent System Operator (CA-ISO). These agents play the role of market participants by formulating bids to maximize their profits. They exercise their skills under a number of scenarios of demand and levels and types of forward contracting for capacity in a simple market without congestion.

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EXECUTIVE SUMMARY

The proposed Available Capacity (ACAP) market proposed by the California ISO in May 2002 requires Load Serving Entities (LSEs) to contract on at least a monthly basis with suppliers to make predetermined production facilities available within the California ISO's Real Time market. The stated goal of the ACAP obligation is to "enable the ISO to verify in advance that adequate capacity is available on a daily basis to meet system load and reserve requirements."[1]

The challenge ahead in designing the rules for an ACAP market is to ensure reliable services in the short term *and* in the long term. STEMS simulations allow us to observe, in the safety of a laboratory setting, the effects of different market rules on spot energy prices, which signal the scarcity of capacity and the exercise of market power. Therefore, we use spot energy prices as a signal that system load and reserve requirements are being met. Our analysis can be thought of as a worst-case with respect to the exercise of market power, under an assumption of inelastic demand.

Primary Results

Using agent-based market simulation and analyzing the results of spot capacity and energy markets has yielded a number of observations. Our first observation confirms that pure capacity markets, those that contract solely for capacity, do not directly affect energy prices in the short term[2]. Therefore, the short-term energy market compensates suppliers again for capacity shortages. This observation motivated the second case in which energy strike prices (energy options) are added to the capacity contracts in order to moderate spot energy market behavior and better ensure that signals for additional capacity are moved to the capacity market.

Subsequent experiments verify that the addition of energy options may diminish price spikes in the spot energy market, and that overall capacity and energy costs to consumers may also diminish in the long term. The effect is that forward capacity contracts with energy options enable LSEs to purchase demand response that can be exercised in the spot market and thereby limit market power in situations of scarcity, *even when* suppliers enter the spot energy market unhedged.

We conducted sensitivity tests to see how the allocation of energy options among suppliers may affect the competitiveness of the spot energy market. Within the context of our experiments, we allocated contracts to only the existing eight suppliers. The *Shaved* allocation is one that targets the largest suppliers first, along the theory that this will most quickly reduce the presence of pivotal players. The *Proportional* allocation is more like a random allocation of contracts to

[1] See Appendix "CA-ISO Filing on ACAP," for details.

[2] Pure capacity markets do affect spot energy markets in the long term to the extent that they promote new entry and the development of additional capacity, but capacity contracts with energy options have a more powerful effect.

suppliers. The *Economic* allocation is based on prioritizing the allocation of contracts by unit from high to low marginal operating cost. Units with higher marginal costs are typically correlated with lower capacity costs and opportunity costs, and so they are more likely to contract first in a competitive capacity market.

The columns of Table ES-1 list the different levels of demand, the amount of reserve margin present for that level of demand (available capacity is always 21.05 GW), and the smallest portfolio that yields competition in the spot energy market for each level of reserves and allocation method.

Table ES-1
Balance of Reserves and Option Portfolios

		Smallest Portfolio that Promotes Competition		
Demand (GWh)	**Reserve (%)**	**Shaved**	**Proportional**	**Economic**
21.0	0.2	X	X	X
20.5	2.6	4	5	5
20.0	5.0	4	4	4
19.5	7.4	3	3	3
19.0	9.7	3	3	3
18.5	12.1	2	2	3
18.0	14.5	2	2	2
17.5	16.9	1	1	1
17.0	19.2	0	0	0

None of the portfolios we tested promoted competition when the Reserve Margin was only 0.2%. One could potentially interpret this as bad news. However, another interpretation could be that the utilities have purchased a price cap at 250 $/MWh for the full quantity of their load. Thus, when supply is truly scarce (only 0.2% reserve is available), the remainder of the signal for new capacity is contained in the cost for this price cap.

A Shaved allocation of Portfolio 4 is sufficient to promote competition in the spot market when the Reserve is at 2.6%. At the same reserve level, Proportional or Economic allocation of Portfolio 5 is needed. These portfolios promote competition at the expense of the exercise of market power. Thus, when there are no pivotal suppliers (demand is 17 GWh or less) portfolios are not necessary to promote competition, because the spot energy market is naturally competitive.

The main idea promoted by Table ES-1 is that a balance between reserves and portfolios of capacity contracts with energy options can successfully promote competition in spot energy markets.

1 INTRODUCTION

The Available Capacity (ACAP) market, as proposed by the California ISO, involves an obligation for Load Serving Entities (LSEs) to contract on at least a monthly basis with suppliers to make predetermined production facilities available within the California ISOs Real Time market. The stated goal of the ACAP obligation is to "enable the ISO to verify in advance that adequate capacity is available on a daily basis to meet system load and reserve requirements."[3]

The challenges ahead in designing the rules for an ACAP market are to define the terms and conditions of the standard contract and to decide what quantity of such contracts are sufficient to provide reliable services in the short term *and* in the long term. In addition, our tool of choice, STEMS, allows us to observe primarily the effects of difference market rules on prices, and one of the signals that prices represent is the shortage of capacity. Another is the exercise of market power. Therefore, we need better to understand the extent to which high prices signal that the system is becoming unreliable in order to gain convincing conclusions from STEMS.

We will address the questions of capacity contract terms and conditions, and we will report what their impact is on limiting price spikes and increasing reliability. The question of long-term incentives for adequate capacity is somewhat beyond the scope of this study. However, it is certainly related to and affected by the kind of short-term decision-making made within the current context, and we will attempt to forecast the impacts that these decisions will have for the long term.

The methodology that follows, for studying particular aspects of market design, is still in its infancy. It draws its inspiration from the area of Experimental Economics [1, 2, 3], wherein a number of enthusiastic researchers have found ways to prove experimentally that the real practice of economics differs from what theory assumes or predicts to be true. Thus, the theory is augmented or revised.

Our version of experiments does not rely directly on real economic practice, nor does it rely completely on theory. It is an attempt to write computer programs for deciding how to bid into electricity markets in ways similar to those found by the experimental economists, who typically use real people. We have conducted a benchmarking study [4] in which we compare market behavior resulting from these two types of decision-makers, and we find that the markets behave very much the same from a qualitative standpoint. Similar findings were drawn from a larger effort done by the Santa Fe Institute [5].

[3] See Appendix CA-ISO Filing on ACAP, for details.

In the following, we divide our challenge into parts, thus isolating the aspects of market power and reliability so that we can be better understand their effects on market behavior. We first simulate a spot capacity market, demonstrate that prices can be arbitrary, and show how market power permeates its behavior. Next, we add energy strike prices to the capacity contracts. This gives value and meaning to the contract prices and shows that the energy market can be made competitive. Finally, we offer a forward scheme for providing capacity that can significantly dampen real-time capacity signals, and thus ensures system reliability.

2
EXPERIMENTAL SETUP

This chapter describes the experimental setup for testing Available Capacity Market designs in terms of the *environment* in which decision makers must operate, the *market institutions* that are present in this environment, which is essentially the decisions to make and how consequences are determined, and finally the *behavior* of the agents as they make their decisions.

We will analyze two models of Available Capacity contracts. The first type of contract is has no energy strike price and allows suppliers to bid any price in the energy market. We call this *pure capacity* contracting. The second type of contract is the purchase by the demand side of a price cap for the provision of energy from individual units. We refer to this as *option* contracting, and explain the details of both types later in this section. Option contracting also allows the supplier to bid any price into the energy market, but has provisions for side-payments to the load side should the energy price rise too high. These side payments make it appear to suppliers as if the demand side is responding to changes in the energy price through their impact on revenues. We will refer to this appearance as *price response*, sometimes also referred to as demand elasticity.

Environment

We describe the economic environment for our experiments in three parts. The first part is what we call the *market model*. For our purposes, it is essentially the contents of a document file describing the market. Second is the *scenarios*, which have as independent parameters the demand and the amount of contracting for available capacity or demand response, depending on the type of contract. Under these scenarios, we investigate two types of contracts, which are described in the Institutions section. Third is *information availability*, which describes what the agents know at the time they make bid decisions.

Market Model

The market model is a stylized version of the California system. Since we are not accounting for congestion in our experiments, we treat the electricity network as having a single node. An appendix contains a table of data regarding the capacity, marginal costs, and ownership of the generation units. Nominally, demand does not respond to prices; it is inelastic.

All events in our simulations are assumed to take place in the short term — over a period of one hour or less. The exact amount of time involved is important insofar as the assumption that system conditions, and thus market conditions, do not change substantially over this period is valid. There are no random events, like forced outages.

There are eight supply players with varying capacities and variable costs (See Appendix for details). They behave competitively for the most part, but since the participants have knowledge of the total supply and demand, they can act strategically to withhold at a profit under some scenarios. There are two inelastic demand players, which bid a very high willingness to pay for varying levels of demand over the scenarios. This bid is at 250 $/MWh, and effectively acts as price cap. Another way to view the demand bid price, is as a long-term option for new capacity. We will revisit this interpretation in the latter part of our analysis.

Total supply is constant at 21.05 GW, while total demand varies across scenarios to be described next. With 19 GWh of demand, for instance, there are five pivotal players. This means that of the eight players, five have enough capacity to withhold a portion of their resources in order to become the marginal supplier and thus control the price of electricity. Table 2-1 contains the total capacity of each supplier's resources and indicates which ones are pivotal players in this demand scenario.

Table 2-1
Market Participant Resource Capacities and Pivotal Players with 19 GWh Demand

Supply Portfolio	s1	s2	s3	s4	s5	s6	s7	s8	Total
Capacity (MW)	3,900	1,600	2,650	3,800	2,550	2,000	2,750	1,800	*21,050*
Pivotal	yes	no	yes	yes	yes	no	yes	no	*5*

Across the top of the table are labels for the eight suppliers, **s1** through **s8**. With the difference between supply and demand being 2,050 MWh, there are five suppliers with capacity greater than this difference, making them pivotal. That is, if any one of them were to remove their resources from the market, the demand could not be met with the remaining resources.

Scenarios

We expect that the issues in the analysis of ACAP to center around the question, “What is the difference between scarcity and local market power?” On the one hand, scarcity can be seen as a legitimate physical reality in markets and it is believed that prices should reflect scarcity in such a way as to encourage the entry of new supply or the exit of sensitive demand. To highlight this question, we analyze the market under varying loads and levels of contracting between demand and the suppliers.

We vary the level of demand in eleven steps of 500 MWh from 16,000 MWh to 21,000 MWh, and we vary the level of contracting in six steps (or portfolios) that are functions of the given demand. Reducing the demand moves the market environment from one of tight supply to relatively ample supply. Increasing the contracting reduces the incentives of suppliers to raise prices in order to increase profits. For options contracts, they also increase the perception of price-responsive demand.

Table 2-2 contains the explicit values of demand used in our experiments, in total and in terms of the Percent Reserve. The latter is the ratio of excess capacity to the total capacity.

Table 2-2
Demand Scenarios in GWh

Scenario	0	1	2	3	4	5	6	7	8	9	10
Total Demand	21.00	20.50	20.00	19.50	19.00	18.50	18.00	17.50	17.00	16.50	16.00
% Reserve	0.2	2.6	5.0	7.4	9.7	12.1	14.5	16.9	19.2	21.6	24.0

For simulations of pure capacity contracting, the quantity is set equal to the total of the demand for any scenario and the capacity is traded in a spot market for capacity.

For simulations of option contracting, Table 2-3 contains the contract quantities for six scenarios of option portfolios. Note that these values are for Demand Scenario 1 (20.5 GWh). Portfolio 0 is the base scenario and has no contracting for either type of contract, pure capacity or Option. Note also that from portfolio to portfolio, the quantity of contracts at a single strike price can rise or fall. The last row of the table lists the percentage of the total capacity under contract.

Table 2-3
Option Contract Quantities for Demand Scenario 1 (20.5 GWh)

Strike Price	Portfolio 0	1	2	3	4	5
25	-	-	-	-	7,380	13,940
50	-	-	-	7,380	6,560	3,280
75	-	-	3,007	4,373	2,187	1,093
100	-	-	4,373	2,187	1,093	547
125	-	-	2,624	1,312	656	328
150	-	3,007	1,749	875	437	219
175	-	2,499	1,250	625	312	156
200	-	1,874	937	469	234	117
225	-	1,458	729	364	182	91
Total	-	8,838	14,669	17,584	19,042	19,771
% Under Contract	-	42.0	69.7	83.5	90.5	93.9

Figure 2-1 depicts the demand response curves that correspond to each portfolio. They are numbered from 0 to 5. Portfolio 0 is the nominal demand curve, which is inelastic (vertical) at 20.5 GWh. The marginal cost of supply is also shown as a dashed line.

The allocation of the contracts to suppliers is carried out by three techniques, which we call *shaved, proportional,* and *economic*. With shaved allocation, contracts are allocated to the largest suppliers first. With proportional allocation, contracts are allocated to each supplier proportional to their total capacity. With economic allocation, contracts are allocated in the order of the highest to lowest marginal cost. The economic allocation order is typically the order in of increasing capacity and opportunity costs, and thus a simple indicator of the economic order of contracting from lowest to highest priced contracts. Figure 2-2 shows how the portfolios are allocated for Demand Scenario 1. From top to bottom of each column in the chart, each layer represents the incremental quantity of capacity contracts for each of the five portfolios, plus the remainder that is not under contract. An appendix describes in detail how each of these contract allocations is determined for each scenario.

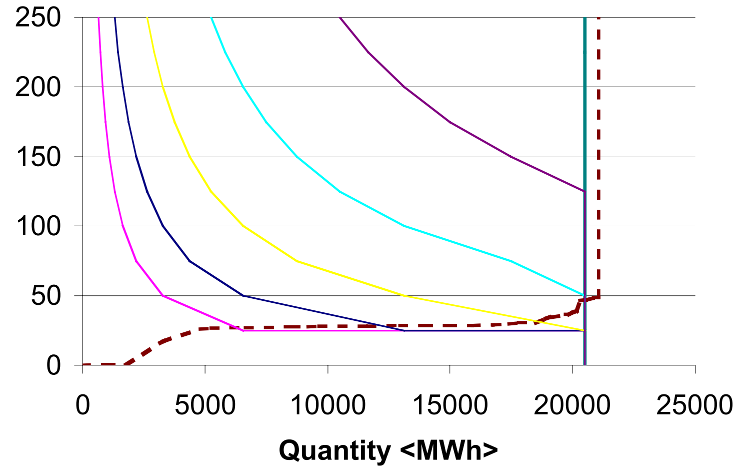

Figure 2-1
Demand Curves for Each Portfolio for Demand Scenario 1 (20.5 GWh)

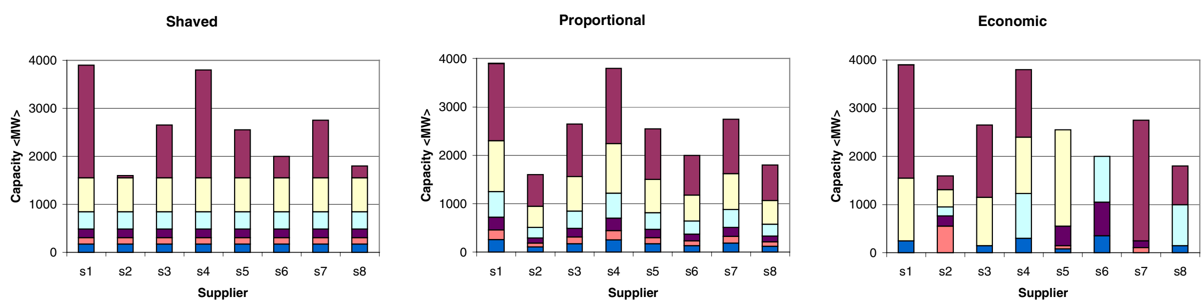

Figure 2-2
Shaved, Proportional, and Economic Allocations of Forward Contracts to Suppliers

Note that we have numbered our scenarios from zero for the base case, and that we will run all combinations of demand and forward contracting scenarios for a total of 66 scenarios. The amount of forward contracting is set as a percentage of the demand, and thus is different for each combination of demand and portfolio thereof.

Information Availability

Available information affects the kind of decision problem that the suppliers can work with, and we endow the supplier agents with three levels of information, Basic, Aggregated, and Network, which they utilize as needed. *Basic* information is the knowledge of their own resource portfolios, their costs, and of public market information like the nodal market clearing prices and their own acceptance schedules. *Aggregated* information is the total supply and demand. This is used to determine whether they are pivotal when there is no congestion. *Network* information is the total supply and demand at each node of the network, the network topology, and the Power Transfer Distribution Factors (PTDFs). This latter information can be used to determine whether they are pivotal if the network were congested.

As part of their resource portfolio, the agents know their contract commitments. This too affects their bidding strategy, which we explain further under the Agent Behavior heading.

Institutions

Our experiments involve three types of economic institutions: forward options contracts and spot markets for available capacity and energy. We describe these institutions in terms of bidding, market clearing, and settlement. Since activity in forward contracting for options is treated exogenously through scenarios, these contracts do not require bidding and market clearing. We have assumed that these steps have already taken place. The bidding and clearing of the simulated spot markets for capacity and energy is carried out identically.

The presence of forward contracts for capacity can affect settlements in the energy spot market. Thus, as part of the settlement discussion, we describe how side payments are made for options contracts.

Bidding

Market participants bid fixed quantities of power at varying prices. The two demand players always bid their willingness-to-pay, which is set at 250 $/MWh. This is how we model inelastic demand. The supply bidders are free to choose the price at which they offer each block, but the maximum willingness to pay on the demand side effectively acts as a bid cap on suppliers. Suppliers must also bid 100% of their capacity into the market at or below this bid cap.

Market Clearing

Market clearing is always done in terms of meeting supply and demand to maximize the social welfare, subject to transmission limits. The problem formulation is a linear program. When the market clears on horizontal portions of the supply and demand curves, the quantity is cleared to satisfy the maximum demand possible.

Settlement Process

Settlement of capacity and energy markets occurs as a result of solving the market clearing problem and utilizing the market clearing price as the uniform price of exchange. That is, each supplier is paid the local market-clearing price (MCP) and each demand pays the local MCP[4].

[4] This is a general rule. Our case has no congestion, so the market will have one price for all participants.

Option Contract

Our option contracts are side agreements having multiple strike prices. Given the Market Clearing Price (MCP), for each Strike Price (SP) the supplier makes a side payment of the quantity MCP-SP to the demand side, if MCP > SP. Otherwise, no side payment is made. Thus, it is as if the demand side is purchasing a price cap from the supplier for the quantity of power under contract. Note that this price cap applies whether the supplier produces the energy or not. Therefore the option itself is financial and not physical in nature. Further, to satisfy the availability criterion, the supplier and the demand side also make direct agreements with the market for exchange of power at the MCP.

Agent Behavior

We have configured the agents in an attempt to eliminate experimental bias. First, the demand players, as mentioned, always bid their willingness-to-pay values. This makes them price takers. The suppliers exercise all of the strategy in our experiments, and each one uses an identical strategy of aggressive profit maximization. They can detect whether they are pivotal players and will attempt to bid at the bid cap if it is more profitable.

Figure 2-3 displays a chart of the number of pivotal suppliers in each demand scenario. Since the ACAP and Options contracts have no impact on the capacity available to a supplier, and they do not impede in any way the manner in which that capacity is bid. So, they do not affect the presence of pivotal players. The Options contract, however, does affect settlements and incentives, which then affects bidding strategies.

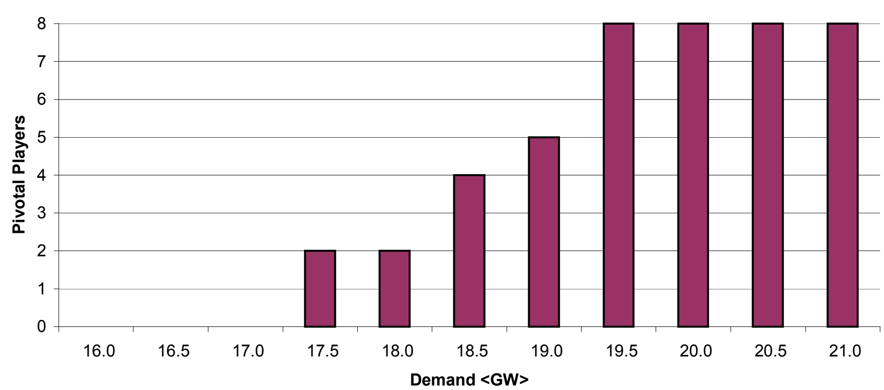

Figure 2-3
The Number of Pivotal Suppliers in Each Scenario

Agents know when they are marginal suppliers by comparing their bid prices with the market-clearing price. As such, marginal suppliers utilize a very simple, naïve rule as a greedy algorithm for rent capture. The rule is that, when they are marginal, they test the margin by raising their bid prices.

Agents have the opportunity to bid and learn the market clearing price and their schedules thirty times. During these thirty rounds of bidding, they learn whether the market is more or less competitive and respond accordingly, by switching between strategies that essentially raise either prices or sales quantity in an effort to increase their profits.

The role of learning is captured in the way that rounds of bidding are repeated for all of the suppliers. In reality, one may say, that this type of repetition does not often occur. Indeed, scarcity events may be rare in occurrence in actual markets. On the other hand, market simulation itself can make frequent in the laboratory what is rare in reality. Thus, we believe it is not only fair, but also important, to offer agents the occasion to learn.

3
EXPERIMENTAL RESULTS

We now describe a program, illustrated through economic experiments, for approaching basic problems of investment and market power in the electricity industry. This program optimizes the returns for both producers and consumers and involves the interactions between system reliability, market power, generation capacity, and electrical energy. These four aspects of the electric power system form the fundamental basis for economic interactions, and they are inextricably linked to system operations. Thus, the story that follows could be of broad interest to almost anyone involved with the electric power system.

Throughout this section, we focus on answering three fundamental questions.

1. Can the demand side buy reliability?

2. From whom?

3. At what cost?

In support of this analysis, we have run simulations to compute two general results: the competitive equilibrium and the simulated equilibrium. The second one is an agent-based calculation, wherein the agents know their own resources and costs and they know the total supply and demand. They bid, record their acceptance in the market and the public information, and then bid again. This is repeated for 30 rounds of bidding, clearing, and settling, all the while the agents are utilizing a heuristic to maximize their profits, individually. These simulations are intended to model a short period, say an hour, over which our input data is relatively constant in actuality. No attempt is made here to handle random events, like forced outages.

The results are for 66 combinations of the independent variables of demand level and forward contracting. Our story begins with a discussion of capacity signals in spot energy markets and proceeds on to how pure capacity markets behave. Following a simulation and analysis of pure capacity markets, we add energy strike prices to the capacity contracts and demonstrate through further simulations and analysis the change in incentives brought about. An appendix explains the elementary analysis of this effect and how it could be implemented in practice.

Capacity Markets

In theory, energy price spikes are supposed to signal the need for additional capacity. There are two main reasons for prices to spike. The superficial reason is that there is a capacity shortage, but more often in practice, the exercise of market power causes prices to rise well before there is a physical shortage of capacity.

In the case of a monopoly supplier, one can imagine that prices would always be high in an electricity market, unless some form of regulatory restraint is in place. There are two main reasons why prices can rise arbitrarily. First is because electricity is such an important product in our modern economy that many cannot do without it. Second, most people are so used to low-cost, reliable service that they take it for granted and do not really consider what the real-time price is when they make purchase decisions.

When more than one supplier is active in a market, the market can be competitive to an extent, but when demand rises to the point where the largest supplier is critical for meeting demand, becoming *pivotal*, the supplier can control the price and (we assume) would do so to maximize their profits. If they do not lose too much quantity to competitors, then the best way to make more money is to raise the price, and consumers will see a price spike. Thus, do price spikes signal market power.

How Markets Pay for Capacity

In our simulation scenarios, energy price spikes are due to the presence of pivotal players, which depends on the relation between capacity and demand. When the gap between the total capacity and total demand in a region is less than the total capacity of the largest player, that player becomes pivotal. As the gap narrows further, more and more players become pivotal. When the gap is smaller than the smallest supplier is, then all of the suppliers are pivotal.

Our simulation experiments show prices spike just after the first player becomes pivotal, and when there are two or three pivotal players, the prices still spike but not necessarily as high. This is because the suppliers bid strategically to undercut each other in order to make more profits. Figure 3-1 shows this happening to a limited extent.

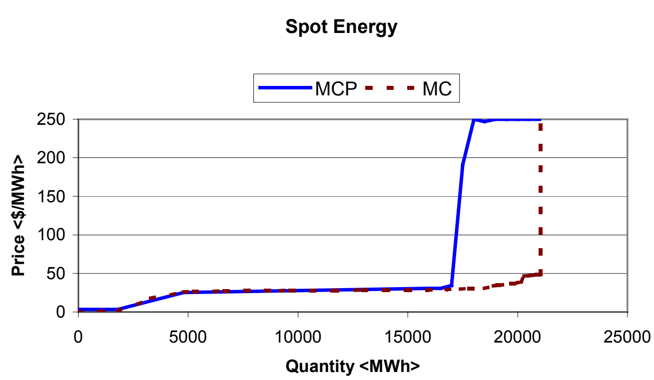

Figure 3-1
Market Clearing Prices and Marginal Costs for Spot Energy

In Figure 3-1, we draw the marginal cost (MC) of supply curve (dashed line) and the simulated market-clearing price (MCP) for our simple market (solid line) as a function of the demand quantity in the horizontal axis. Notice that the price is relatively competitive until the demand for capacity reaches about 17 GWh, where the largest player, with 3.9 GW of capacity becomes pivotal. Then, the MCP spikes to 250 $/MWh. From there, as demand increases, the presence of more pivotal players causes prices to bump around a little, until the point when most or all of the players are pivotal, and the best strategy is unambiguously to bid the highest price possible.

In theory, if an electricity market were run with only a spot energy market, price spikes would be sufficient to signal and compensate for new capacity. The serious problems with this approach are two-fold. First, no reasonable person will allow prices to be untethered. Therefore, bid caps on the spot energy market are always put in place. Some caps not only attenuate capacity signals, but also they almost assure that new capacity will not be fully compensated for fixed cost, because bid caps amount to a subsidy to consumers at the expense of suppliers.

The second serious problem is that spot energy price spikes occur at a point in time when there is no way for new entrants to respond or for demand to be reduced. This timing mismatch is partially addressed by markets for capacity. Whether an Installed Capacity (ICAP) market or an Available Capacity (ACAP) market as proposed by the California ISO, the introduction of these products is an attempt to separate from the spot energy prices the portion that should compensate for capacity.

How Markets Pay for Capacity… Twice

We now turn our attention to simulating a pure capacity market, which is a market for capacity that has no energy component. This type of product is introduced and sold forward of spot energy in an attempt to move capacity signals forward and out of the spot energy market.

Our next experiment looks at the clearing price for a typical capacity market. This could be an ICAP market or ACAP market, since the main input to the market, the marginal cost of additional capacity, is identical for both markets. We simulate a spot capacity market, perhaps held in the day ahead or month ahead. Marginal costs for capacity have the property, in this relatively short time frame, of being almost always zero, until the limit of existing capacity is reached. Since the period is so short, the ability to introduce new capacity into the market in the day or month ahead is very expensive, perhaps infinite. Thus, the marginal cost curve looks like the dashed line in Figure 3-2.

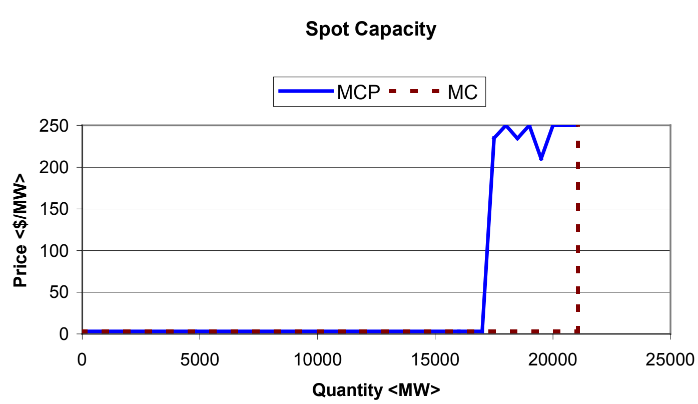

Figure 3-2
Market Clearing Prices and Marginal Costs for Spot Capacity

In theory and in observed practice, short-term capacity prices are either very low (zero) or very high (bid cap). These markets have been criticized from a consumer standpoint because of the way that prices seem, and probably are, arbitrary [9]. In New England, the ICAP market was disinstated about a year after being introduced, because of this perception.

As can be seen from the MCP curve in Figure 3-2, simulated capacity prices are also either very small or very high. In this simulated market, we can directly attribute these spikes to pivotal players, which depend, in the same manner as in the spot energy market, on the relation between capacity and demand.

The MCP curves for spot energy and spot capacity look remarkably similar; we see the same price spikes in both cases. When we see a price spike in such a capacity market, it is highly likely that we will again see a similar spike in the subsequent spot energy market. The logical conclusion is that the spot capacity and the spot energy market are providing duplicate compensation for capacity. That is, the addition of a pure capacity market doubles the strength of the capacity signals.

Such an amplification of the capacity signals is justified if it accelerates the introduction of new capacity. Unfortunately, this is may not be the case. Further, if the capacity market is not run far enough forward, then the signal is still arriving much too late for the producers and consumers to respond appropriately. The impact of pure capacity markets can only be through changes in capacity investments. Since investments are very long term (20+ years), a short-term capacity market does little to foster efficient investment. To promote efficient investment, a capacity market requires sufficient lead time and duration in its contracting.

Pushing Capacity Payments Forward

Reliability, Market Power, and Prices

Capacity markets have been instituted primarily as a means to secure system reliability through a market mechanism. The need for a market mechanism is clear when independent power producers are present and they need real price signals to guide their decision making. This link between sufficient generation and depending on it for reliability purposes is a very well established engineering concept.

What we now want to convey is that in order to move capacity payments truly out of the spot energy markets, to mitigate market power, to provide for sufficient generation, and thus the reliability of the power system, we need to think differently. We need to introduce economic thinking to our engineering thinking. We need to establish a new balance between engineering needs and economic needs, should there be any chance at a solution to our difficulties in providing reliability and accurate investment incentives.

To think differently about reliability and investment, we need only to consider and have some faith in the economic idea of substitute goods.

Reserves and Demand Response

That electric power systems are now controlled almost exclusively from the generation side is an artifact of the evolution of the system, driven primarily by consumer preferences and technical capability. Since early customers were actually being sold light as a product, power systems were developed with multiple generators for reliability and with governing mechanisms to maintain voltage and thus light levels. As more lights were turned on, the generators would work harder, and vice versa. Customers wanted steady light sources, and the thought of using technical capability to control the light sources instead of the generators was quite impractical.

Other early operations arose where mechanical water-driven systems were replaced with electric generators and electric motors for significant efficiency gains. These systems would have been in the opposite situation, because they depended in the local source for power. When the water supply was limited, control was put on the load. That is the factory produced less, and vice versa.

According to this second example and engineering practice, there would be no need for a reserve requirement if demand (factory output) could appropriately respond to contingencies (water shortages) and the primary supply was sufficiently reliable (never failed). According to economic theory, prices can be used to signal the availability of supply (water) and the various loads (production lines) could use those prices as a way to know how to keep the most profitable ones running. Thus, price rises should signal contingencies. Thus, according to engineering practice and economic theory, with more demand response we require less reserves, and vice versa.

This means that reserves and demand response are substitute goods. If consumers buy more of one, they need less of the other. If we introduce this concept of substitution between reserves and response, we open our thinking to new and different solutions to our problems with market power and investment.

The Secret Formula

In this section, we conduct simulation experiments to answer the question, “Is buying options like buying response, like buying reserves?” We simulate five portfolios of options over various levels of demand to see whether these portfolios can make the spot energy market competitive even under tight supply. In the following example, we use the shaved allocation method of forward contracts.

To illustrate this concept in practice, we plot the results for the scenarios when demand is at 20.5 GWh, leaving 550 MW of capacity in reserve for a margin of 2.6%. Figure 3-3 has curves for the marginal cost of supply (MC) and the nominal (inflexible) demand (Dem). The latter is considered Portfolio 0, where there are no options in place. Then, we also see the demand curves for the five portfolios of options. Each of the portfolio curves (from 0 to 5) has a circle on it. These circles indicate the simulated market clearing prices.

It is now clear that when the reserve margin is at 2.6% that Portfolios 0 through 3 are ineffective at removing price spikes from the spot energy market; each of these scenarios yields a simulated spot price of 250 $/MWh. However, Portfolio 4, with shaved allocation, transforms the spot energy market into a competitive one. Portfolio 5 shows no incremental effect on prices compared to Portfolio 4.

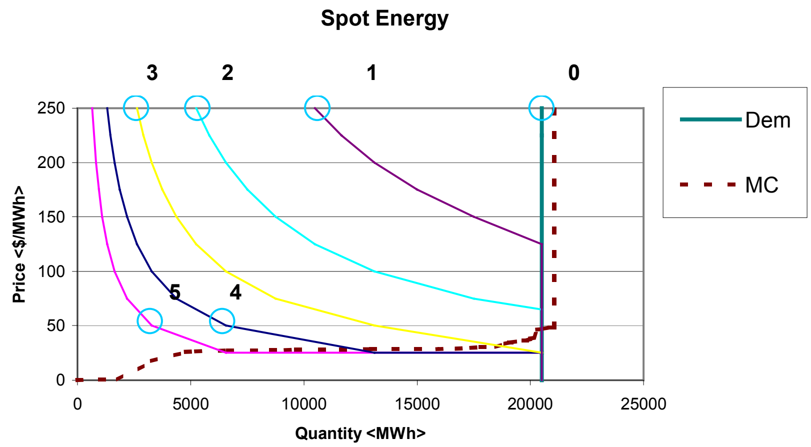

Figure 3-3
Simulations of Five Options Portfolios

Note that since the clearing price is at about 50 $/MWh, the clearing price is placed around 5000 MWh for Portfolios 4 and 5. This should be interpreted as having the spot energy market contributing this order of magnitude to the load, while the options at prices below the MCP supply the remainder. All of the demand is indeed provided with supply, it is just that the financing comes from a combination of spot energy and called options.

When the spot energy market is competitive, as in Portfolios 4 and 5, the signals for new capacity have been removed from there and pushed into the market for the option portfolios. Thus, spot payments are going primarily for energy and scarcity rents, and forward payments for the option portfolios are primarily compensating for capacity and market power.

How It Works

To see a high level view of how competition is introduced by options contracts, we consider the fact that lines of constant profit follow a hyperbolic function in price and quantity, since the simple formula for profit is

$$Profit = Price * Quantity - Cost(Quantity).$$

In our simulations, we know exactly all the elements of these components of profit.

To illustrate the mechanism for creating competitive spot energy markets, imagine as a worst case that a monopolist supplies the market. (In effect, when a player is pivotal, they are indeed behaving as such.) Therefore, we can compute the isoprofit curves of this monopolist and plot them out as if they are the lines of constant elevation on a mountain of profit, as in a topographic map. Figure 3-4 is such a drawing.

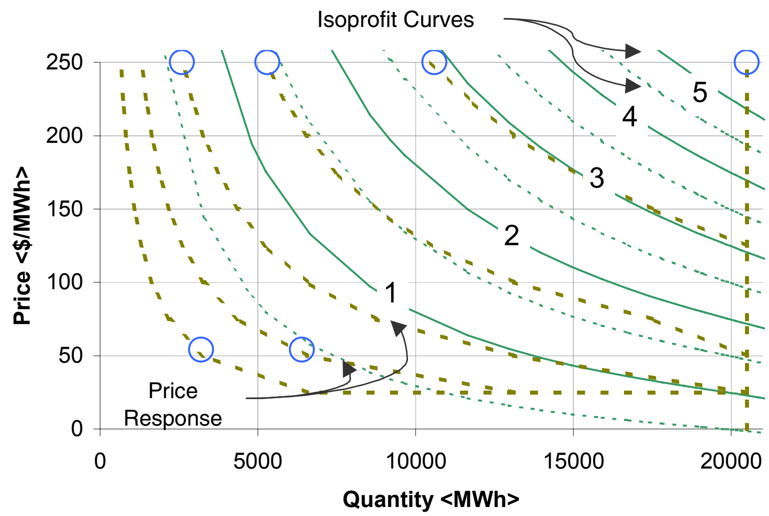

Figure 3-4
Trails of Demand on a Topology of Monopoly Profits

The isoprofit lines are labeled in millions of dollars of profit. Also in this figure are trails (bold dashed lines) on this topology of profit that represent the nominal demand (vertical at 20,500 MWh) and the five portfolios of options. Portfolio 1 is farthest from the origin, and Portfolio 5 is closest. On each of the portfolio curves is a circle that represents the simulated Market Clearing Price, obtained from STEMS.

The important lesson to be taken from Figure 3-4 is that the alignment of the trails with the isoprofit curves dictates to the monopolist which way is uphill toward higher profits. For Portfolios 0 through 3, that direction is through higher prices. For Portfolios 4 and 5, higher profits are obtained through increased sales.

For a more detailed explanation of this effect along with a scenario for its practical implementation and accompanying simulation experiments see the Appendix called *Elementary Analysis*.

Now, the stage is set for a different way of thinking about reserves, demand response, and regulations. We have seen that the traditional regulation of reserves have been problematic in a market setting, mostly because the markets for pure capacity (reserves) are not able to separate capacity and energy as products and thus do not promote the potential advantages of having them priced and compensated separately. By simply adding a portfolio of energy strike prices to the pure capacity product, we are in effect summoning the pack mules, dynamite, picks, and shovels and using them to cut a well designated trail across the profit terrain. This trail regulates the demand side of the market and via the market mechanism gives the suppliers sufficient incentive to compete.

In fact, the Regulator can choose the course of this trail to effectively separate capacity and energy as electricity market products, gaining significant advantages for both producers and consumers. In this way, the demand side can indeed purchase system reliability, and push capacity payments into the forward markets.

Choosing Suppliers

As explained earlier, our experiments were run with three allocations of contracts to suppliers: Shaved, Proportional, and Economic. Nevertheless, there are several other important aspects to forward contracting. For capacity contracting, the time of contracting and the period of performance are critical aspects, because it is important for consumers that the market signals for new capacity occur when there are many opportunities for participants to respond.

As we have said before, real time, day ahead, and even month ahead offer little or no opportunity for response. On the other hand, should a contract be settled long in advance, say three years, and should the period of performance be similarly long, say five years, then even a major new project could be built and on line to serve under guaranteed cost recovery for its first five years.

Longer time frames support not only new entrants, but also demand-side programs. A utility could equally well contract for full-blown demand response from its own customers. Such contracts in effect put supply- and demand-side programs on an equal footing, providing important price checks and a multitude of choices.

Contract Allocations

Our contract allocation methods were tested to show how the allocation of contracts is related to their effectiveness at making the spot energy market competitive. Within the context of our experiments, we allocated to only the existing eight suppliers. The Shaved allocation is one that targets the largest existing supplier, along the theory that this will reduce the presence of pivotal players. The Proportional allocation is more like a random allocation of contracts to suppliers. The Economic allocation is meant to mimic actual practice, but is highly affected by the original resource allocation.

The columns of Table 3-1 list the different levels of demand, the amount of reserve margin present for that level of demand (supply is always 21.05 GW), and the smallest portfolio that yields competition in the spot energy market for each level of reserves and allocation method.

None of the portfolios that we tested promoted competition when the Reserve Margin was only 0.2%. This is denoted by X's in those locations of the table. One could potentially interpret this as bad news. However, another interpretation could be that the utilities have purchased a price cap at 250 $/MWh for the full quantity of their load. Thus, when supply is truly scarce (only 0.2% reserve is available), the signal for new capacity is contained in the cost for this price cap.

A Shaved allocation of Portfolio 4 is sufficient to promote competition in the spot market when the Reserve is at 2.6%. At the same reserve level, the Proportional or Economic allocation of Portfolio 5 is needed to ensure a competitive spot market.

These portfolios promote competition at the expense of the exercise of market power. Thus, when there are no pivotal suppliers (demand is 17 GWh or less) portfolios are not necessary to promote competition, because the spot energy market is naturally competitive.

Table 3-1
The Balance of Reserves and Option Portfolios

		Smallest Portfolio that Promotes Competition		
Demand (GWh)	**Reserve (%)**	**Shaved**	**Proportional**	**Economic**
21.0	0.2	X	X	X
20.5	2.6	4	5	5
20.0	5.0	4	4	4
19.5	7.4	3	3	3
19.0	9.7	3	3	3
18.5	12.1	2	2	3
18.0	14.5	2	2	2
17.5	16.9	1	1	2
17.0	19.2	0	0	0

The main idea promoted by Table 3-1 is that a balance between reserves and option portfolios can successfully promote competition in spot energy markets.

The Value of Forward Capacity

We turn our attention now to addressing the question of costs. How much does the portfolio approach cost, relative to the pure capacity markets or doing nothing? To answer this question, we need to have an idea of how the power system performs over the long run.

Duration Curves

Long-run system performance is encapsulated in the Load Duration Curve, which is a measurement of the distribution of load levels over a given period of time, usually a year. So, let us assume that the period of performance for our portfolios is one year, and that the load duration curve looks like that plotted in Figure 3-5. The left vertical axis ranges from zero load to 20 GWh. Thus, the curve can be interpreted at any point as giving the probability that the load is less than some value. For instance, the probability that demand is below 16.0 GWh is about 0.97.

Also shown in the figure is the price duration curve. This curve is computed from the load duration curve by simulating the value of the load and obtaining a market-clearing price. Therefore, for a load of 16.0 GWh, the simulated price is 30.6 $/MWh. We use this curve to interpret the probability of various prices. For instance, the probability that the MCP is below 50.0 $/MWh is 0.983. This means that the chance of a price spike over the year's duration is about 2.7% according to our assumptions about the load.

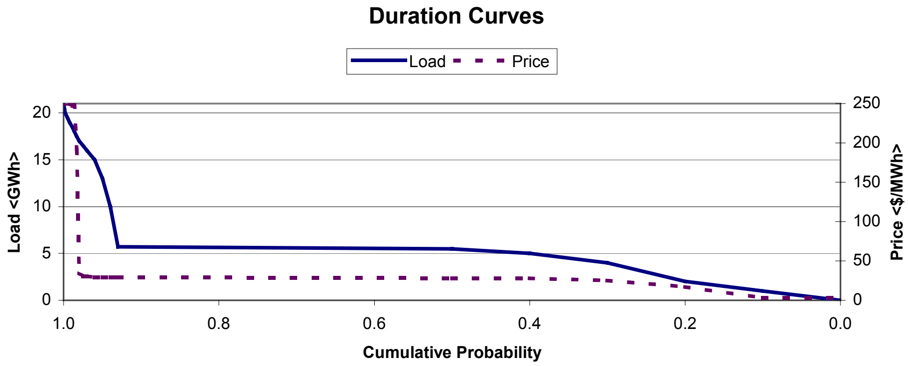

Figure 3-5
Typical Duration Curves for Load and Market Clearing Prices

Forward and Spot Expenses

We now use the two duration curves to compute the costs of the portfolios and of spot energy. The combined costs of forward contracts and spot energy over the year's duration can then be compared to help us understand the total cost to the consumer of each approach.

Details of the calculations are in an Appendix. Therefore, without too much detail, we will explain how the ACAP (pure capacity) contracts, Portfolios, and Spot Energy are priced. The capacity contracts are assumed conservatively to cover the total load, without reserves. We determine their cost by simulating, for each value of the load, the spot capacity MCP, and then by summing up the product of these two values and the probability of that load scenario. This yields the expected cost per hour of these capacity contracts.

Similarly, to value the Portfolios, we begin with Portfolio 1, using the simulated spot energy prices for Portfolio 0 (no contracts), we do the same inner product of load, prices, and probabilities to compute the expected cost per hour. We then cost out Portfolio 2 using energy prices simulated with Portfolio 1 in place, and so on up to Portfolio 5. Thus, the portfolio costs are computed conditional on the prior portfolio. In this way, each portfolio is priced on the margin, and market power is purchased away from the suppliers in incrementally and efficiently.

We cost out spot energy by conducting simulations with and without Portfolio 5 in place, assuming Shaved Allocation. Recall that Available Capacity contracts with no energy strike prices have no effect on the spot energy prices, but Portfolio 5 does. The expected savings from calling these options are subtracted from the expected spot energy costs.

Before we explain the results, we should point out that the magnitudes of the results are largely affected by the relative choices of bid caps for the capacity and energy markets. We chose to set the levels of these two caps to the same value to allow this comparison between capacity costs and long-term energy costs. On the other hand, the conclusions to be drawn from this table would not be affected should the two caps have vastly different relative values.

Table 3-2 summarizes these calculations. The expected cost to put Portfolio 5 in place is 47.3 k$/h. It results in expected spot energy costs of 304.0 k$/h, for a total expected cost of 351.2 k$/h. If we use this method to serve the expected load of 11 GWh, the resulting long-run expected cost of energy and capacity over the year is 32.0 $/MWh. With only the spot energy market, the long run expected cost is 36.5 $/MWh.

Table 3-2
Expenses for Capacity and Options Contracting and Long Run (LR) Costs

	Fwd k$/h	Spot Energy k$/h	Total Cost k$/h	Exp. Load GWh	LR Cost $/MWh
Portfolio 5	47.3	304.0	351.2	11.0	32.0
Spot Only	-	401.2	401.2	11.0	36.5
ACAP	90.8	401.2	491.9	11.0	44.8

Finally, the expected cost of Available Capacity contracts without reserve margins, based on simulated spot capacity prices, is 90.8 k$/h. This value would be significantly higher should we purchase reserves in addition. It is higher than that for Portfolio 5, because there is no strategy to buy it on margin, since pure capacity contracts do not affect the spot energy price. We reuse the simulated Spot Only energy cost to get a total expected cost of 491.9 k$/h, and an expected long-run cost of 44.8 $/MWh.

Notice that the difference in Spot Energy costs between Portfolio 5 and the other two such entries in Table 3-2 is 97.2 k$/h. This difference is the expected cost of market power and capacity in this market, when there is no forward contracting. It actually costs 47.3 k$/h to purchase Portfolio 5, which separates capacity and energy, because this portfolio can be purchased in a series of tranches, where each tranche slowly removes more and more market power from the spot energy market.

Our simulations and cost calculations imply that the options portfolio approach to recompense capacity and provide reliability is lower cost than provisions by either spot energy or available capacity markets.

4

CONCLUSIONS

Using agent-based market simulation and analyzing the results of spot capacity and energy markets has yielded a number of observations. Our first observation is that pure capacity markets do not affect energy prices. Therefore, the energy market pays again for capacity shortages. This motivates the addition of energy strike prices to the capacity contracts in order to modify spot energy market behavior.

By choosing a portfolio of strike prices and contract quantities, we can virtually carve out a demand response curve that actually ensures that the spot energy market will always be competitive. This simple exercise is related to estimating supplier profitability, and then choosing a portfolio that promotes the incentives for competition. As a result, market signals for additional capacity are pushed into the forward market, where they are more likely to provoke an appropriate response. This is an effective way of separating the capacity and energy markets.

The objective of the CA-ISO's design for an Available Capacity is to ensure that adequate capacity is available to meet system load and reserve requirements. Our simulations of various balances of reserves and demand response (implemented through option portfolios) has helped us to recognize and quantify a balance between these two important components of a power system that promotes efficient markets for power. In reality, reserves will probably remain the foundation for system reliability, but utilizing demand response in concert is likely an even more effective way of providing for system reliability, especially to the extent that it can promote efficient long-term planning. A balance of the two shows promise in reducing price spikes in frequency and severity. It reduces costs to the consumer, and it helps to secure returns for both supply- and demand-side investments.

We conduct simulations and analyses on simple and closed systems, realizing that the real world is much more complex. As examples of complicating factors, consider the following:

- Power systems have congestion, making location and isolation important considerations.
- Capacity markets must operate in the context of priority obligations for Must Run contracts, further promoting locational considerations.
- Forced outages for change the balance of reserves and demand response, necessitating the consideration of uncertain events on capacity markets.
- The potential for entry of new suppliers and demand-side programs changes the way competition behaves and the cost estimates.
- The portfolio of available generation changes from day to day.
- Forward contracting suffers from a free rider problem. It is often beneficial for one buyer to let others purchase the first set of contracts, which lowers the cost for subsequent contracts.

- Penalties for non-compliance by either the Load Serving Entities or suppliers may be needed to guarantee a successful implementation.

How would these factors change things? These and other questions should be addressed to better understand how reserves and demand response behave as substitute goods.

The principle that demand response can be purchased in terms of option portfolios and that these can partially substitute for reserves is simple and robust. It even opens the door for a promising new perspective on how to regulate electricity systems. The program we described here is just the beginning of what could become a practical and useful method for ensuring stability and well-needed benefits to both producers and consumers of electric power.

Finally, while considerable thought and preparation went into the design and execution of our agent-based simulation software and experimental technique, the process of conducting a real-life analysis was symbiotic. The software and technique benefited from conducting the analysis, because it presented new challenges and hurdles that make us further challenge every assumption. Likewise, the analysis benefited from the technique, because it exposed new perspectives and dimensions of the analysis that were not expected during the preparation stage. The analysis further benefited from the use of software agents because this technique offers the ability for quick changes that then fosters the exploration of unexpected avenues.

5
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A

ELEMENTARY ANALYSIS

Let us examine a few elementary cases of forward contracting and a process by which capacity contracts with energy strike prices can lead to incentives for enhanced competition. To motivate and to better enhance the reader's understanding of the experiments in the body of this report, we provide the following elementary analysis of markets for electricity capacity and energy. It is structured as a sequence of problems and potential solutions for a cast of characters: a Regulator, a Single Buyer, and either a monopoly supply or a duopoly of identical suppliers in a market. This idealized market is both challenging and transparent, and for these reasons, it serves well as an example of our experimental methodology.

In restructured electricity markets, a Public Utility Commission (PUC) can impose requirements only on Load Serving Entities. Our simulation results show that it is possible for a PUC to promote competition among suppliers through the incentives promoted by forward capacity contracts having energy strike prices. In this way, each supplier has an incentive to adhere to a policy of incremental cost bidding. The advantage of this method is to use incentives rather than policing as the instrument encouraging compliance.

In each of the cases that follow in this appendix, we use the same system supply and demand curves. In the Monopoly case, one supplier owns the entire supply. In the Duopoly case, the same supply is split evenly between two identical suppliers. The total system supply will always be 24 GWh, with a linear marginal cost curve satisfying

*Marginal_Cost(Quantity) = Incremental_Marginal_Cost * Quantity,*

with a value of *Incremental_Marginal_Cost* = 50/20,000 = 2.5e-03. There is a bid cap of 250 $/MWh. With this marginal cost function, the production cost is calculated as

*Production_Cost(Quantity) = 0.5 * Incremental_Marginal_Cost * Quantity^2.*

It should also be clear then that the total supplier profit satisfies the formula

*Profit(Quantity) = Price * Quantity – 0.5 * Incremental_Marginal_Cost * Quantity^2.*

The total demand will always be 20 GWh and inelastic. As a result, the competitive equilibrium satisfies the full 20 GWh of demand with a price of 50 $/MWh. The supplier's total Cost is $500,000 on revenues of $1,000,000, yielding $500,000 profit.

The rest of this appendix is a structured description of what the Regulator can do to logically promote the use of capacity contracts with energy strike prices and then what the Single Buyer and suppliers could possibly do in response.

The Regulator's Problem

The Regulator faces the difficulty of balancing long- and short-term considerations for the supply's cost compensation and for the Single Buyer's ability to purchase energy at least cost. Traditionally, this problem has been approached as a challenge in regulatory ratemaking with a solution in the realm of monitoring a monopoly's costs[5] and setting the price for electricity on a cost-plus basis. In place of the ratemaking approach, let us investigate a market-based approach to solving this problem.

Monopoly Supply

We will refer to the single supplier as the Monopolist, and let us assume that the Regulator monitors the Monopolist's costs and can thus estimate its profits based on a range of combinations of demand and market clearing price. Knowing this, it is possible for the Regulator to determine a function for demand response that gives the monopoly the incentive to bid their marginal cost. The rationale follows.

In Figure A-1, for the supplier we introduced in the previous section, we have plotted the lines of constant profit every $500,000, with whole millions being solid lines, and the half-millions being dashed. The solid lines are labeled from 1 to 4 million dollars. So, over the range of prices (0 to 250 $/MWh) and quantities (0 to 20,000 MWh), the maximum profit is about 4.5 million dollars.

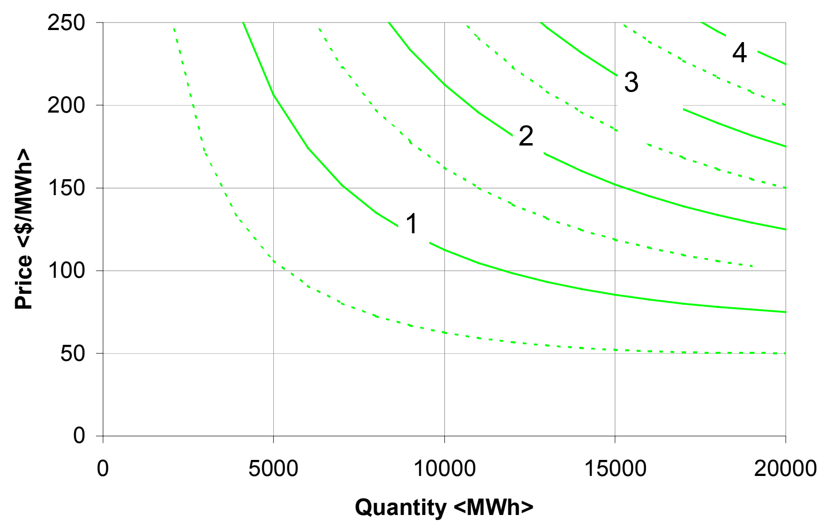

Figure A-1
Isoprofit Curves of a Monopoly Supplier with Constant Marginal Costs

[5] See, for instance, LAFFONT, J.-J. AND TIROLE J. "The Politics of Government Decision-Making: A Theory of Regulatory Capture," *Quarterly Journal of Economics*, Vol. 106 (1991), pp. 1089-1127.

One reason for the traditional cost-plus solution to regulating monopoly electric suppliers is that demand for electricity has been notoriously unaffected by prices in the short term, that is over minutes or days. This is referred to as *inelastic* demand. In the next figure, Figure A-2, we have added an inelastic demand curve at 20,000 megawatts as a dashed line.

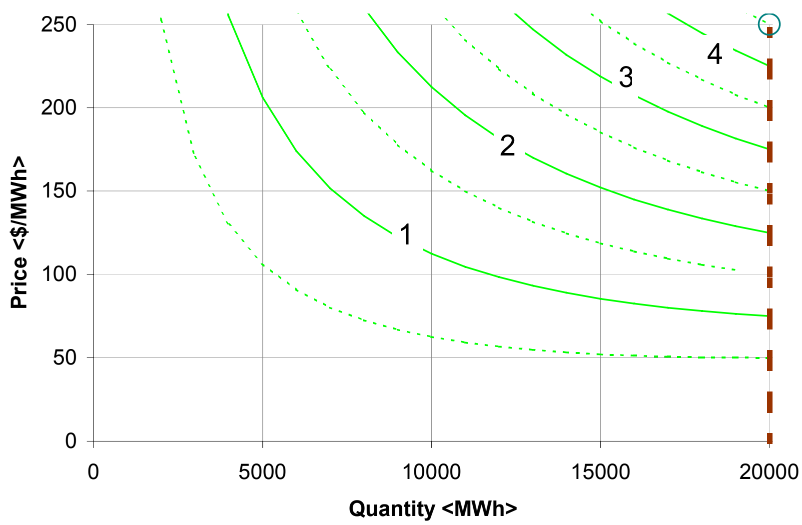

Figure A-2
Isoprofit Curves with Inelastic Demand

The difficulty with a market solution to the Regulator's problem becomes obvious, as we can see that the Monopolist would charge the highest price possible (250 \$/MWh) to maximize profits at \$4.5 million, as indicated by a circle at the top of the demand curve.

Now suppose that the value of demand has some elasticity or sensitivity to price. We plot again in Figure A-3 the same isoprofit curves, but with a demand curve that shows response to increasing prices. The formula is

*Price(Quantity) = 50 * Demand/Quantity.*

This formula limits the Monopolist's revenue to a constant equal to *50*Demand*. Since *Demand* = 20000 MWh, revenue is limited to \$1,000,000.

Even though demand is quite sensitive to prices in this case, the solution for the supplier is still to charge the highest price possible for a profit of \$980,000, as indicated by the circle at the top of the demand curve. This is because the isoprofit curves are shallower than the demand curve. This is also evident in the revenues as plotted in Figure A-4. Let's see what happens when the opposite is true, when the demand curve is shallower instead.

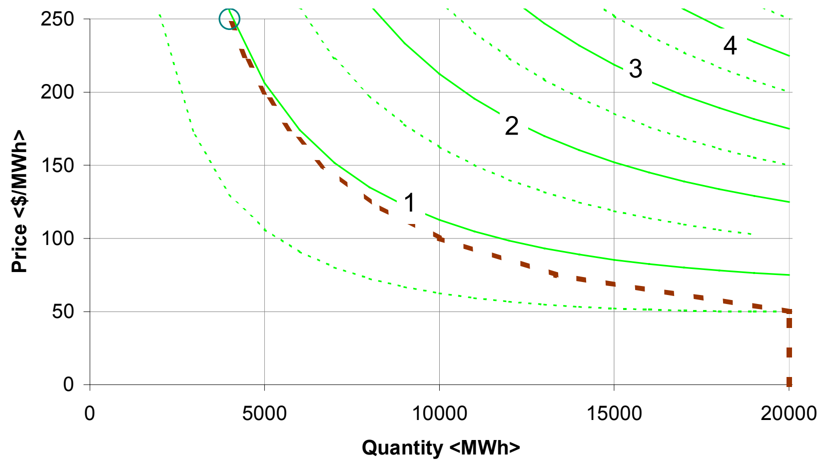

Figure A-3
Isoprofit Curves with Elastic Demand but Non-Competitive Prices

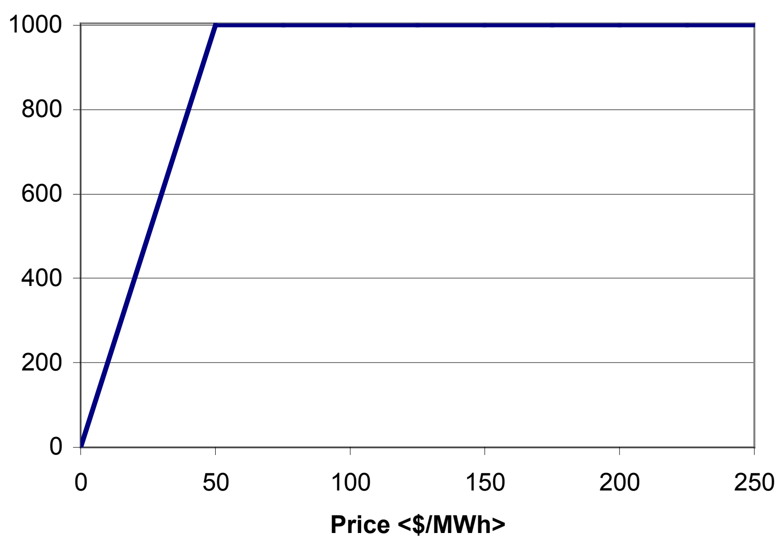

Figure A-4
Monopoly Revenue versus Price for Elastic Demand

As a final example of this principle, we examine what the market clearing price would be if we increase the amount of elasticity of demand even further so that the demand curves are more shallow than the monopoly's isoprofit curves.

In Figure A-5, the high point of profit on the demand curve is no longer at the top, but at the bottom. The effect now is that the monopoly would rather charge lower prices in order to maximize its profits. The Monopolist now makes $500,000 profit by offering to sell electricity at 50 $/MWh in the market. The formula for this demand curve is

*Price(Quantity) = if (Quantity < 13000, 50 * Demand/(Quantity + 7,000), 50).*

In this formula, we have subtracted off 7,000 MWh from the demand under an assumption that the Single Buyer has the ability to contract for that quantity of competitive supply or demand reduction at 50 $/MWh. (Note that the CA-ISO itself currently has 1.2 GW of third-party supply contracts that it can use to present such a demand reduction to the market.) This type of contract is needed against a monopoly supplier, because implementing only a strict revenue limit still leaves an incentive for the monopoly to minimize cost in order to maximize profits. A formula of the form

*Price(Quantity) = Const * Demand/Quantity.*

presents a revenue cap to the Monopolist, and the only way to reduce costs is to sell less. But the effect we want is for the Monopolist to have the incentive to sell as much as possible. So, to overcome this disincentive, we shift the demand curve to the left by 7,000MWh.

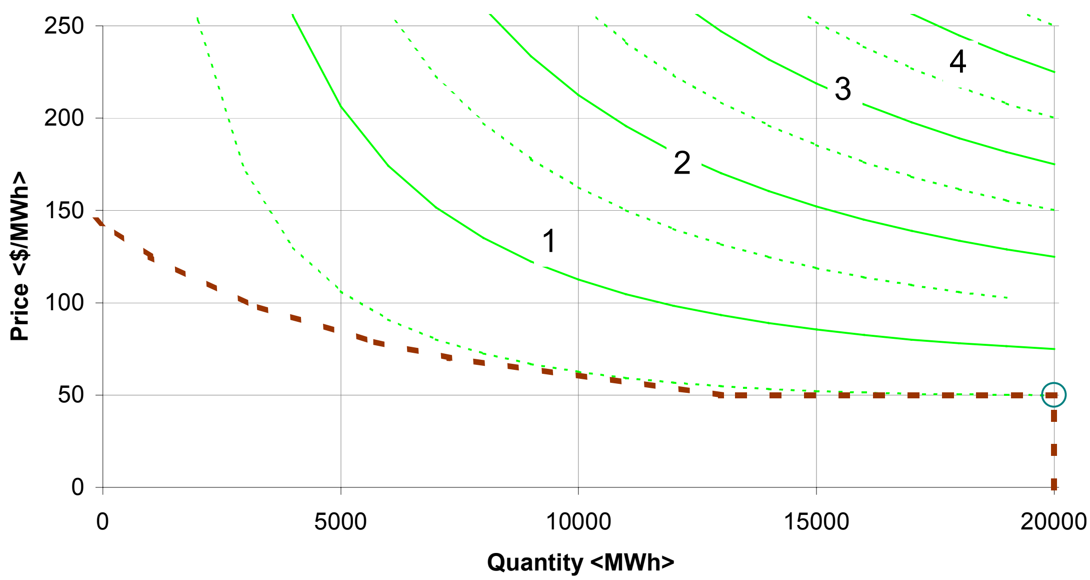

Figure A-5
Isoprofit Curves with Competitive Prices

The corresponding revenue curve is plotted in Figure A-6. There is a discontinuity in the revenue function at the price of 50 $/MWh, because the residual demand curve is flat for 7,000 MW at that price, implying that the residual demand will drop by this amount should the bid price rise above this value.

What we have shown, within the assumptions of this simple and transparent example, is that if the Regulator were to ensure that the Monopolist perceives that its revenue as a function of the market-clearing price (its bid price) is limited in the manner depicted in Figure A-6, the demand will be perceived to have a response to price. This response will create sufficient incentives for the Monopolist to bid a competitive price (marginal cost) in the energy market.

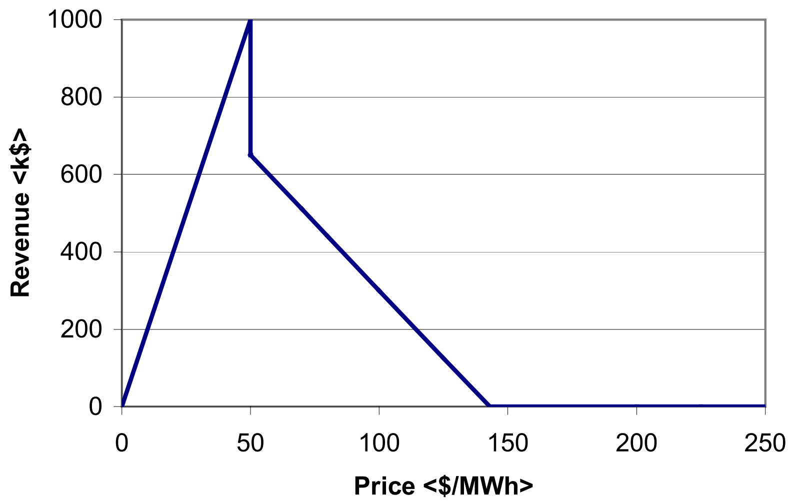

Figure A-6
Monopoly Revenue versus Price that Promotes Competitive Prices

Duopoly Supply

We now change the Regulator's problem by switching from having one supplier to having two, owning identical sets of resources. For consistency, we adopt the assumption that there can be no physical withholding of supply, which has the effect of placing a lower bound of 8,000 MW on the production of a given supplier and likewise bounds their production costs. When there is a Duopoly supply, any one supplier faces not just the potential response of the demand side to price, but also the potential response of its competitors. For simplicity, let us assume that the market has two identical suppliers, each with 12,000 MWh of supply having linear marginal costs with slope 50/10,000 $/(MWh)^2, and that total demand is 20,000 MWh. Each supplier then has isoprofit curves like those in Figure A-7.

These curves shoot vertical at 12,000 MWh, because the supplier cannot make money above that quantity.

For the sake of argument, let us temporarily assume that one of the suppliers always bids competitively. We will refer to this one as the *Competitive Fringe*. The other we will call the *Duopolist*. Since we also assume that the Duopolist will supply whatever its competitor does not, that it does not physically withhold supply, then the isoprofit curves will shift slightly.

In Figure A-8, the residual demand curve faced by the Duopolist has the shape of the bold dashed line. It was determined as the combination of 20,000 MWh of inelastic demand and 12,000 MWh of competitive supply. Note also that isoprofit curves for quantities less than 8,000 MWh have fixed production cost of $160,000, based on the assumption that the minimum supply is 8,000 MWh. The isoprofit curves between 8000 and 12,000 MWh assume that production increases at half the rate of the *Quantity*. That is, the Duopolist splits the increasing demand in half with the Competitive Fringe, as would be the case by them bidding their cost functions.

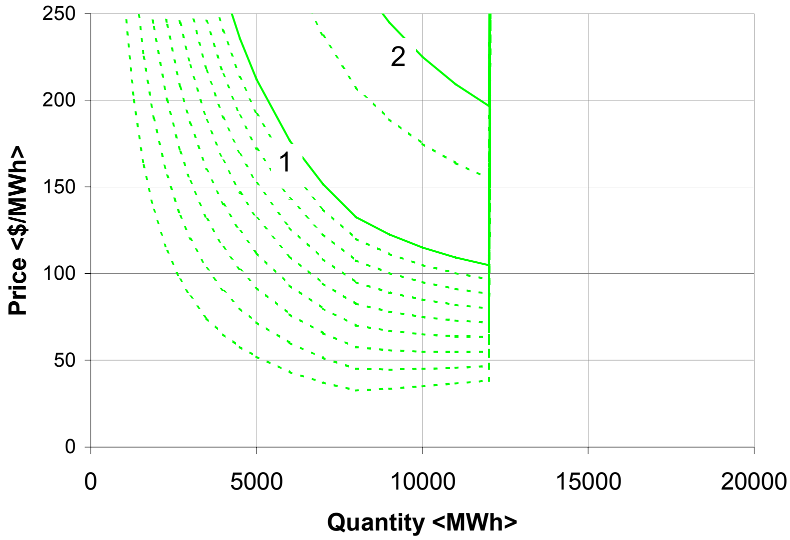

Figure A-7
Isoprofit Curves of a Duopolist

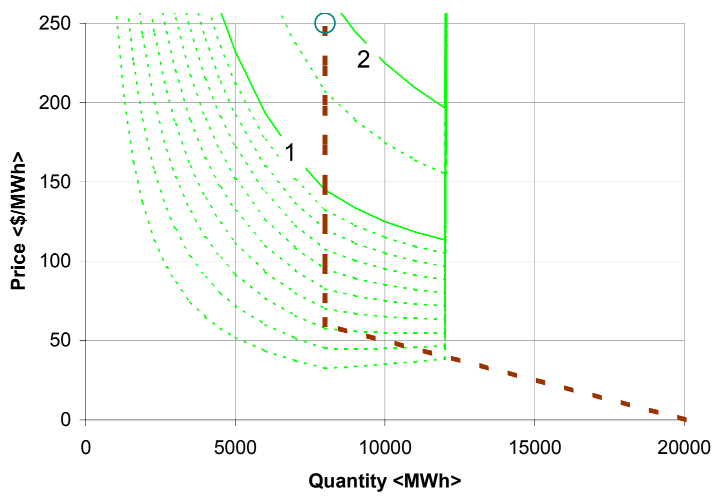

Figure A-8
Isoprofit Curves of a Duopolist with Inelastic Demand and Competitive Fringe

The equation for the residual demand curve is

*Price(Quantity) = if (Quantity <= 8000, 250, 2 * 2.5e-3 * (20,000 – Quantity)),*

which is valid for values of Quantity between 0 and 20,000 MWh.

Note that as the Duopolist chooses to bid a higher price, the Competitive Fringe takes a larger and larger bite out of demand. Despite this, the optimum for the Duopolist in Figure A-8 is still to raise the price to the bid cap at 250 $/MWh, for a profit of $1,840,000.

As in the Monopoly case, imagine now that the Single Buyer becomes price responsive according to the following formula:

> Price(Quantity) = if (Quantity < 10000, 250,
> if (Quantity < 16400, 400000/(Quantity – 8400), 50)).

This three-part function is plotted in Figure A-9. It has the characteristic of maintaining the value of the bid cap (250 $/MWh) out to 10,000 MWh. Then, the price drops along the contour of *400,000/Quantity* out to the *Quantity* of 16,400 MWh, reaching the competitive price of 50 $/MWh. Then it is flat, out to the total demand value of 20,000 MWh.

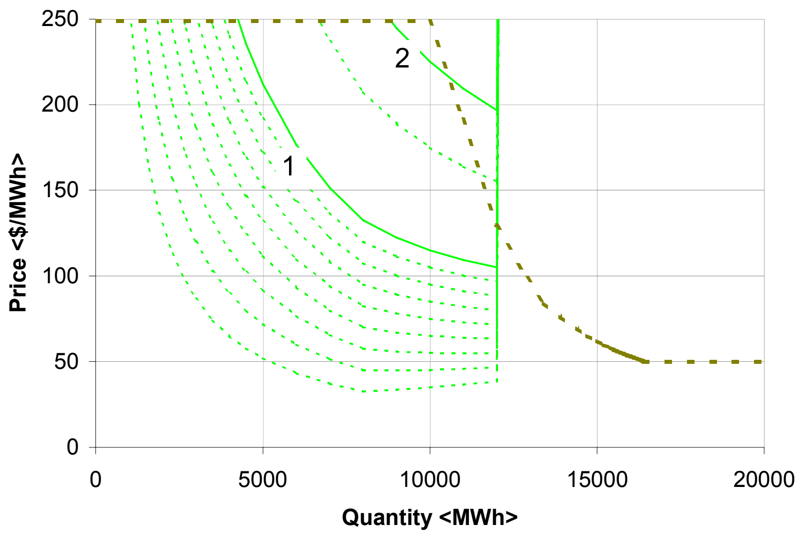

Figure A-9
Demand Response for Single Buyer versus Duopoly

Combining the demand response seen in Figure A-9 with the effect of the Competitive Fringe seen in Figure A-8, we get the composite residual demand function seen in Figure A-10. The formula for this function is:

> Price(Quantity) = if (Quantity < 3066, 400000/(Quantity+3600),
> if (Quantity < 6400,
> 0.5*(42 – 0.005*Quantity + [(0.005*Quantity + 42)^2 - 0.84*Quantity + 8000] ^0.5,
> if (Quantity < 10000, 50, 5*(20000-Quantity)/1000)))

This combined response has four parts. Starting with the *Quantity* at zero, for the first 3,066 MWh the function follows a hyperbolic contour down to a price of 60 $/MWh. At this point, the hyperbolic demand curve and the linear competitive supply curve merge together for another 3,334 MWh, until the price reaches 50 $/MWh. The *Price* in this region is from the solution of a quadratic equation, where we use the 'plus' alternate. Then, for 3,600 MWh, the price remains constant at 50 $/MWh. Finally, from 10,000 MWh to 20,000 MWh, the function follows a line to a price of zero, which corresponds to the effect of the competitive supply.

In this case, the optimal solution for the Duopolist is to offer a price of 50.0 $/MWh for a profit of approximately $250,000. We can see this by comparing the iso-profit contours to the residual demand curve. A circle at the point (10000, 50) indicates the high point of the assumed residual demand curve over the profit topology.

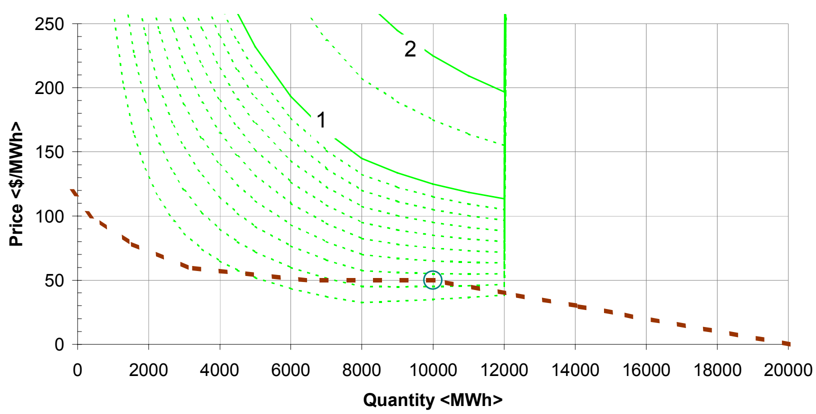

Figure A-10
Isoprofit Curves of a Duopolist with Shallow Demand and Competitive Fringe

The interesting thing to note at this point is that the added effect of the Competitive Fringe having 2,000 MWh above the competitive equilibrium value of 10,000 MWh is to enhance the demand response in the eyes of the Duopolist. We can see from this latest figure that the market will remain competitive, which is an essential goal of ACAP as originally formulated by the CA-ISO in their MD02 project.

Returning to our earlier assumption and to conclude our thought experiment for the Regulator's Problem under a duopoly, let us verify that the second supplier will bid competitively. We have determined a demand response curve that makes the first one bid a competitive price of 50 $/MWh. If both suppliers were subject to this response, then they both would bid the same price, by symmetry. So, the effect of having the Single Buyer exhibit price response of the specified form is that it will simultaneously incent both suppliers to behave competitively.

In this Duopoly example, we have shown two things. First, sufficient demand response can make a Duopoly market become competitive. This should be no surprise, given the similar result for the monopoly. We note at this point that it is sufficient for the given response to take the form of an impact on suppliers' revenue in order to have the proper effect on profits and thus incentives for bidding competitively.

Second, the presence of surplus competitive supply enhances the effect of demand response. This surplus is like reserves, except that it must be bid at marginal cost in order to have the effect of enhancing demand response as embodied in the option contracts. But since the Regulator can stipulate a demand response formula to ensure competitive bidding, competitive bidding, as an institution, can become self-reinforcing and self-fulfilling, leading to a stable equilibrium.

As mentioned, the demand response perceived by the suppliers should sufficiently affect the revenue transfers from the Single Buyer to the supply side. For each supplier to perceive the demand response depicted in Figure A-9, the Single Buyer would need to affect each supplier's spot energy revenue to be the following function of the market-clearing price

Revenue(Prod, Price) = if [Price <= 50,

*Prod * Price, (Prod – 1800) * Price – 8000 * (Price – 50)].*

The Single Buyer's expenditures are the sum of the suppliers' revenues,

Expenditures(Price) = Revenue(Prod1, Price) + Revenue(Prod2, Price),

where their production values, *Prod1* and *Prod2*, satisfy *Demand = Prod1 + Prod2*. Using this identity, we obtain a general formula for the Single Buyer's expenditures:

*Expenditures(Price) = Demand * Price + if (Price <= 50, 0, 800000 – 19600 * Price).*

Next, we will explain how the Single Buyer can hedge regulated expenditure cap of this form, by replicating its effect with contracts.

The Buyer's Problem

When the burden of a spot energy expenditure limit is placed on the Single Buyer, it then has the problem of representing its actual, inelastic demand as being price responsive in the wholesale market, a challenge that is not insurmountable. We now show how the Single Buyer can replicate demand response curves for each case in the previous section (Monopoly and Duopoly) through purchases of forward contracts.

First, we explain two contracts that can be used as elementary building blocks to replicate the given form of a demand curve. These contracts are called a Call Option and a Right-To-Dispatch contract. Then, we replicate the Monopoly and Duopoly demand response curves of the Regulator's Problem using these two contracts. The result is two portfolios of forward contracts that the Single Buyer would purchase, if it faced a Monopoly or a Duopoly, as insurance against anticompetitive market behavior.

Replication of Elementary Demand Response

The next two sections each describe a scenario with an elementary demand curve, a challenge to the Single Buyer to replicate that curve with contracts, and the response of a monopoly supplier to that level of demand response.

The first contract is for a *Call Option*. This is a contract where the Single Buyer buys the right to call on a quantity of energy at a predetermined strike price. When the market price is above the strike price, the contract acts to cap the expenditures of the Single Buyer for the contracted quantity of energy. The counter party to such a contract would perceive it as a revenue cap and is still free to bid all of its capacity at any price it chooses.

The second contract we call a Right-To-Dispatch (RTD) contract. In this case, the Single Buyer buys the right to make dispatch decisions on a quantity of energy capacity. Should the capacity be dispatched, the Single Buyer pays its counterparty an agreed strike price. Since the Single Buyer has dispatch rights, the contracted quantity of capacity is bid into the market by the Single Buyer and not its counterparty. We also consider the energy payment under such a contract to be exempt from an expenditure cap on the Single Buyer. This is because we want this contract to reflect the same kind of operating conditions that self provision of energy would entail.

Call Option

Let us begin with an example using a Call Option. Assume that the Single Buyer must serve the *Demand* of its customers, who are not price responsive, and that the regulated shape of the demand curve follows the form

*Price = Regulated_Constant * Demand/Quantity,*

where the Regulator sets the value of *Regulated_Constant*. This is equivalent to regulating the amount that the Single Buyer pays for electricity to be a linear function of Demand, because

*Revenue = Price * Quantity = Regulated_Constant * Demand.*

In other words, the *Regulated_Constant* is a really a regulated, average price for power.

It is sufficient for the Single Buyer to replicate this form of regulated demand response by purchasing a call option for the entire quantity of demand with a strike price being the *Regulated_Constant*. We describe this contract with the following parameters:

Option_Contract_Price = Regulated_Constant
Option_Contract_Quantity = Demand

If the Single Buyer is facing a monopoly supplier and there is a finite *Bid_Cap*, this amount of demand response may not provide sufficient incentive for the monopoly to behave competitively under unfettered market conditions[6], because the incentive for a monopoly under a constant revenue constraint is to withhold its supply to minimize costs. The maximum profit for the Monopolist is achieved by restricting the quantity produced to the amount served at the bid cap, as denoted by the following formula

[6] Note that FERC currently maintains both a bid cap and a must-offer obligation over the Western U.S. While these conditions are important aspects of the reality of market participation, the main point here is to take note of the incentive for withholding, and later to offer a remedy.

*Quantity = Regulated_Constant * Demand/Bid_Cap.*

This allows the monopoly to charge the bid cap, yielding a profit of

*Profit = Regulated_Constant * Demand – 0.5 * Incremental_Marginal_Cost * (Regulated_Constant * Demand/Bid_Cap)^2*

For these values being as previously stated, we get *Quantity* = 4,000 MWh and *Profit* = 980,000.

Right to Dispatch

Our second elementary example is to have a form of demand response that satisfies the equation

Price(Quantity) = if (Quantity < Demand – Second_Step_Width, Bid_Cap, Regulated_Constant).

This is a price function consisting of two steps. The first step is at the *Bid_Cap*, and is *(Demand – Second_Step_Width)* wide. The second step is at the *Regulated_Constant*, and has the width of the *Second_Step_Width.*

The Single Buyer can achieve this type of response by purchasing a contract for the right to control the dispatch of generation capacity for *Second_Step_Width*, with the condition that all energy from the capacity will be paid a price equal to *Regulated_Constant*. We call this a Right-To-Dispatch (RTD) contract with parameters as follows:

RTD_Contract_Price = Regulated_Constant,
RTD_Contract_Quantity = Second_Step_Width

Its effect is that the Single Buyer, having dispatch rights, will bid this capacity into the market at the contract price. Should a supplier bid higher, it will lose the opportunity to supply that quantity of power.

With this amount of demand response and the Single Buyer's counterparty being the Monopolist, the optimal strategy for a monopoly, assuming that *RTD_Contract_Quantity < Demand*, will be to bid the bid cap for a profit of

*Profit = Bid_Cap * (Demand – RTD_Contract_Quantity)*
*+ Regulated_Constant * RTD_Contract_Quantity*
*- 0.5 * Incremental_Marginal_Cost * Demand^2.*

For *RTD_Contract_Quantity* = 7000 MWh and the same values of the other constants that we have been working with, *Profit* = $3,100,000.

We now return to our continuing story where the Regulator has effectively imposed expenditure limits on the Single Buyer. Note that while viewing regulations as expenditure limits is convenient for exposing the forward contract regime, much deeper subjects surrounding default service obligations and the regulatory compact remain in flux as electricity sectors restructure.

These deeper subjects, being more fundamental, must be well defined and resolved *before* long-term contracting has a safe harbor under a market-based system.

The next case is when the Single Buyer faces a monopoly supplier and the other case is when the Single Buyer faces two suppliers, a duopoly.

Monopoly Supply

The challenge set out by the Regulator for the Single Buyer against a monopoly is to purchase a combination of contracts that implement a level of demand response in the form of expenditures as defined by the following formulae:

*Expenditures(Quantity) = Quantity * Price(Quantity),*

*Price(Quantity) = if (Quantity < 13000, 50 * Demand/(Quantity + 7000), 50).*

By inverting the function *Price(Quantity)*, we obtain the following alternative formulae:

*Expenditures(Price) = Quantity(Price) * Price,*

*Quantity(Price) = if (Price <= 50, Demand, (50 * Demand)/Price – 7000).*

It should be apparent from the prior description of using contracts to replicate demand response that for *Demand* = 20,000 MWh the given formula can be replicated by the Single Buyer having one Call Option contract and one RTD contract. The numerator of 50 * *Demand* suggests that the entire demand be covered with an option at 50 $/MWh. The denominator adder of 7000 suggests an RTD contract for 7,000 MWh at 50 $/MWh, which must be obtained from a party other than the Monopolist in order for it to have the precise hedging effect. This analysis yields contracting parameters as follows:

RTD_Contract_Price = 50 $/MWh,
RTD_Contract_Quantity = 7000 MWh,
Option_Contract_Price = 50 $/MWh, and
Option_Contract_Quantity = 20,000 MWh.

The Option contract will limit expenditures to $1,000,000 on the 20,000 MWh of load it covers. So, the Monopolist will make payments back to the Single Buyer as

Option_Payment(Price) = if (Price <= 50, 0, 20000(Price – 50)).*

The 7,000 MWh RTD contract will place a step of that length on the lower end of the demand curve. Recall that we consider the Single Buyer expenditures for the energy portion of the RTD contract to a third party (or internal to the Single Buyer) to be exempt from the regulatory expenditure limit in order for the the Single Buyer to meet the formulaic expenditures requirement.

The combination of the two contracts forms a hedge for the regulated demand response. Net expenditures to the Monopolist then satisfy the equation

Monopoly_Expenditures(Price)
*= if (Price <= 50, Price * 20000, Price * 13000 – 20000(Price – 50))*
*= if (Price <= 50, 20000, (50 * 20000)/Price – 7000) * Price,*

which is identical to the prior formula for *Expenditures(Price).* This proves that the specified schedule of contracts can hedge the Regulated expenditure restrictions on the Single Buyer.

Duopoly Supply

Facing two suppliers, the challenge set out by the Regulator for the Single Buyer is to hedge limited revenues by maintaining expenditures according to the function

*Expenditure(Price) = Quantity(Price) * Price,*

where

Quantity(Price) = if (Price <= 50, 20000, if (Price <= 250, 800000/Price + 400, 0)).

Let us take two steps to determine the contracts that correspond to this level of demand response. The first step is to look at a set of options contracts that limit expenditures to $800,000 on 16,000 MWh of demand, and the second is to look at an RTD contract that provides 3,600 MWh demand response at 50 $/MWh.

The options contract parameters can be determined from the $800,000 numerator in the *Quantity* function and the knowledge that the Regulator is attempting to achieve a competitive result of 20,000 MWh transfer at 50 $/MWh. Dividing the $800,000 in this function by the competitive price yields that 16,000 MWh should be under contract.

The RTD contract parameters can be determined from the remainder of the Demand (20,000 MWh) that is either not under options contracts (16,000 MWh) or under contract at all (400 MWh). This quantity is 3,600 = 20,000 – 16,000 – 400. The strike price is taken to be the desired competitive equilibrium price, 50 $/MWh.

The difference that two suppliers make over the Monopoly case is that the Single Buyer must hedge against the behavior of both at once. By the symmetry of the two suppliers' positions in the market, this means that both suppliers should perceive demand response equally, and to do this, the Single Buyer should contract equally with both. This case requires the Single Buyer to purchase one 8,000 MWh Call Option with a strike price of 50 $/MWh from each of the two suppliers.

The Single Buyer will also need RTD contracts on 3,600 MWh quantity with a strike price of 50 $/MWh. These contracts do not need to be taken out with the two suppliers in order for them to perceive the Single Buyer's response. In our case, they are. So, an added benefit is not part of the regulatory requirement. The extra benefit is that, since the Single Buyer bids the corresponding resources, the suppliers cannot use the capacity under RTD contracts to exercise market power. We will split the RTD contracts evenly between the two suppliers, so that each has 1,800 MWh at 50 $/MWh.

Thus, the regulated demand response curve can be hedged by purchasing one Call Option and one RTD contract from each of the two suppliers. The contracts will have the following parameters:

Regulated_Constant = 50 $/MWh,
RTD_Contract_Quantity = 1,800 MWh, and
Option_Contract_Quantity = 8,000 MWh.

These contracts cover 19,600 MWh of the load. The remaining 400 MWh of load is left to competitive forces.

The Seller's Problem

In this final section of our Elementary Analysis chapter, we will address the problem faced by suppliers. We first look at the Monopolist, and then the two suppliers in the Duopoly.

At this point, we depart from our earlier analytical style in two ways. First, we take the chains off the Competitive Fringe in the Duopoly case and allow them to bid aggressively to increase their profits (if they can). Second, to illustrate and analyze the seller's problem, we will utilize STEMS to simulate the sellers' behavior. In each case, supplier(s) face an inelastic demand curve, but there is a forward position in Right-To-Dispatch contracts and/or Option Contracts that affects the manner in which a supplier can best increase profits. The simulation of these cases will demonstrate that the Single Buyer is indeed well hedged by the forward position as we obtain competitive results.

In using STEMS, we have to approximate the smooth marginal cost functions of the suppliers with step function. This leads to small inaccuracies and anomalies, which we will explain for each case. The main method of approximating these curves is to design the staircase steps so that the smooth curve passes through the center of each step. The Monopoly curves have block sizes 1,000 MWh, while the Duopoly supply curves have block sizes of 500 MWh. An Appendix specifies all of the suppler marginal cost curves.

Monopoly Supply

The Monopolist has forward contracts with the Single Buyer, which was motivated by the Regulator's restrictions. To illustrate that this type of bidding is well hedged by these contracts, we conduct a simulation run with the Single Buyer holding the requisite hedging contracts.

In the this simulation, the Single Buyer submits an inelastic bid curve with the formula

Price(Quantity) = if(Quantity <= 20,000, 250, 0), but there are two forward contracts in place. There is a 20,000 MWh Option contract at 50 $/MWh, and a 7,000 MWh RTD contract with a third party at 50 $/MWh. The result is that the full 20,000 MWh is served at 50 $/MWh.

Duopoly Supply

The bidding agents in STEMS are subject to a critical constraint that significantly affects the Seller's Problem under a Duopoly. The constraint is that any given seller has no knowledge of the other sellers. They know the total supply and demand, so they know that there indeed exist other suppliers, but they cannot tell beforehand how these suppliers will behave.

Depending on what a seller knows about the market, different results will occur in the market. If the players all know what each other is doing, then the Duopoly example we have outlined would result in very high prices. For example, in a Cournôt equilibrium formulation [10], where all of the suppliers know everything, the result would be a market clearing price of 250 $/MWh. As another example, a Conjectured Supply Function Equilibrium formulation [11] obtains differing results, depending on the critical assumption of the competitor's response to price. Recall that demand is inelastic, so if the assumption (conjecture) is that a competitor will respond to price changes less quickly than the change in a bidder's marginal profit, then the result is a price of 250 $/MWh. As the response quickens to be faster than the change in a bidder's marginal profit, the equilibrium price will fall, eventually reaching the competitive value of 50 $/MWh.

The contracts that hedge the demand curve are two 8,000 MWh Options contracts at 50 $/MWh and two 1,800 MWh RTD contracts at 50 $/MWh. Each supplier is given one of each contract. As a result, it can be verified that the Single Buyer's expenditures will satisfy the function

*Expenditures(Price) = Quantity(Price) * Price,*

where

Quantity(Price) = if (Price <= 50, 20000, if (Price <= 250, 800000/Price + 400, 0)).

Thus is the Single Buyer provided with a sufficient hedge.

The simulation result, which is based on the information constraint on the bidding agents, is that the market-clearing price comes out to be 50 $/MWh with 20,000 MWh served. This differs from the Cournôt result, exactly because the agents in the simulated result are operating under a sufficient information constraint. The agent-based result implies that the regulatory structure that institutes forward capacity contracts could provide sufficient incentives for competition between even two suppliers.

Summary

Table A-1 summarizes the simulation results. The values for the Served Load are mostly 20,000 MWh, by design. The profit values of the Duopoly cases are above the theoretical value of $250,000 each, because the marginal step of the supply functions has a price just below 50 $/MWh. These profit values too could be brought closer to the theory by using smaller step lengths at the equilibrium. We did not do so, because convergence to the (p, q) value did not depend on making the supply step lengths more resolved.

Table A-1
Simulation Results for Elementary Analysis

Case	Market Clearing Price ($/MWh)	Served Load (MWh)	Supplier Profits ($)
Monopoly	50.000	20,000	488750.00
Duopoly	50.000	20,000	250062.50 each

The main point to make now, is that the regulated demand response and the combinations of contracts used to hedge them were chosen in this analysis for convenience. The convenience has been that we are using a minimal number of contracts.

It should be clear from the earlier diagrams that compare the demand curves with the isoprofit curves, that these demand curves are overly elastic. The demand curves could be steeper and we would obtain the same equilibrium results. Another way to express this is that the contracts that we have modeled in this analysis result in more expense than is necessary for the market to attain competitive results, because fewer would be sufficient to obtain the same effect.

Another important, albeit subtle, point is to notice that in the same way that the presence of forward contracts can lower the spot price, the opportunity cost of selling a forward contract depends on the configuration of the existing portfolio of all such contracts in the market. Since the effect is generally to lower the spot price, identical forward contracts become cheaper as more are transacted. As a result, an incremental approach to forward contracting is to be preferred by the consumer.

Finally, the long forward period has much greater *supply* elasticity than the spot or even the short forward. Because of this fact, the first set of forward contracts is best transacted long forward. This will keep the entry cost to the forward market as low as possible and also help to better limit the costs of subsequent contracts, by the logic of the decreasing returns to opportunity laid out in the previous paragraph.

In our more detailed experiments in the body of this report, there are eight suppliers instead of at most two, and we utilize a larger number of options contracts with a variety of strike prices, instead of a single Option contract and a single RTD contract. We do not need to use RTD contracts there, because no single supplier is large enough to dominate the market. There, we find that portfolios of Option contracts can be tailored to obtain just the right shape of demand response to induce competitive behavior in a spot energy market.

B
DATA TABLES

Supplier Resources

The following table describes the detailed cost structure of the eight supply portfolios. Our model uses the Total Variable Cost for each block of power (Unit) and ignores the Fixed O&M Costs.

Table B-1
Resource Information for Market Participants

Unit Name	Capacity	Total Var Cost
	MW	**$/MWh**
Supplier 1		
Alamitos 3-6	1900	27.5
Alamitos 7	250	47.0
Huntington Beach	450	26.5
Redondo	1300	28.5
Total	*3,900*	
Supplier 2		
EL Segundo 1&2	400	30.5
EL Segundo 3&4	650	27.5
Long Beach	550	36.5
Total	*1,600*	
Supplier 3		
Morro Bay	1000	28.5
Moss Landing	1500	26.0
Oakland	150	39.0
Total	*2,650*	
Supplier 4		
Coolwater	650	29.5
Etiwanda	1000	28.5
Ellwood	300	48.5
Mandalay	450	28.0
Ormond Beach	1400	27.0
Total	*3,800*	

Table B-1
Resource Information for Market Participants (Continued)

Unit Name	Capacity	Total Var Cost
Supplier 5		
Hunters Point	400	33.5
Pittsburgh	2000	28.0
Portrero Hill	150	36.5
Total	*2,550*	
Supplier 6		
North Island	150	46.5
Encina	950	28.5
Kearny	200	48.5
South Bay	700	30.5
Total	*2,000*	
Supplier 7		
Big Creek	1000	0.5
Mohave	1500	17.5
Highgrove	150	34.5
San Bernardino	100	34.5
Total	*2,750*	
Supplier 8		
Contra Costa	850	29.0
Humboldt	150	38.0
Helms	800	0.5
Total	*1,800*	

Marginal Cost of Supply for Elementary Analysis

The two suppliers in the duopoly case have the same marginal cost curves. These are essentially half of the Monopolist's supply. The price is determined as the price of the midpoint of each block. So, the price of the Monopolist's first block of 1000 MW is determined on the basis of its midpoint at 500 MW and the incremental marginal cost of 0.0025 $/MWh^2.

Table B-2
Monopoly and Duopoly Marginal Cost Curves

Marginal Cost <$/MWh>	Monopolist Quantity <MW>	Duopolist Quantity <MW>
1.250	1000	500
3.750	1000	500
6.250	1000	500
8.750	1000	500
11.250	1000	500
13.750	1000	500
16.250	1000	500
18.750	1000	500
21.250	1000	500
23.750	1000	500
26.250	1000	500
28.750	1000	500
31.250	1000	500
33.750	1000	500
36.250	1000	500
38.750	1000	500
41.250	1000	500
43.750	1000	500
46.250	1000	500
48.750	1000	500
51.250	1000	500
53.750	1000	500
56.250	1000	500
58.750	1000	500

Duration Curves

The load duration curve is an assumed input for the convenience of valuing forward contracts. The values were chosen be be representative, but not specific to any particular region. We list in Table B-3 not only this load duration curve, but also price duration curves that result from our simulations of the demand scenarios that correspond to the points in the load duration curve.

The values for the MCP under Portfolios for load being 1.8 GW and 4.8 GW are average values over those ranges. Since these values are constant across the portfolios, their approximation does not affect the conclusions.

Table B-3
Load and Price Duration Curves

Probability	Load	MCP ACAP	MCP Portfolio 0	MCP Portfolio 1	MCP Portfolio 2	MCP Portfolio 3	MCP Portfolio 4	MCP Portfolio 5
0.001	21.0	250.00	250.000	250.000	250.000	250.000	250.000	250.000
0.001	20.5	250.00	250.000	250.000	250.000	250.000	54.218	54.218
0.003	20.0	250.00	249.998	249.998	249.998	241.080	48.145	48.145
0.003	19.5	210.41	249.996	249.996	162.647	38.748	38.748	38.748
0.003	19.0	250.00	249.997	249.997	156.285	36.898	36.898	36.477
0.003	18.5	234.42	247.125	249.995	36.345	36.345	35.947	34.469
0.003	18.0	249.99	249.995	249.995	33.368	33.368	33.368	33.443
0.003	17.5	234.58	191.350	31.752	31.752	31.752	31.752	31.293
0.005	17.0	0.00	34.508	34.508	34.508	34.508	34.508	30.255
0.005	16.5	0.00	30.503	30.503	30.503	30.503	30.503	29.418
0.570	16.0	0.00	30.605	30.605	30.605	30.605	30.605	28.378
0.200	4.8	0.00	25	25	25	25	25	25
0.200	1.8	0.00	3	3	3	3	3	3

C

CONTRACT ALLOCATIONS

To get the amount of contract for each strike price and each supplier, we use the following procedures.

Let the number of supplier be n and S_i, $i = 1,\ldots,n$ be the amount of available resources for supplier i. We adopt the convention that $S_{n+1} = 0$ and $\sum_{i=i1}^{i2} S_i = 0$ if $i1 > i2$. Additionally, we assume that $S_i >= S_{i+1}$ for all $i = 1,\ldots,(n\text{-}1)$.

Starting with the lowest strike price $p = p_1$,

Step 1: Evaluate the amount of total contract required at the specified strike price p, $C_T(p)$.

Let p_0 be the strike price next lower to p. If p is the lowest strike price, then set p_0 to 0. Denote M as the bid cap for the energy, α the parameter representing the "elasticity" for the demand function, and D the inelastic demand, then for the data in the range specified in this report, we can express the contract required as

$$C_T(p) = D * \alpha * (1 - 1/p) \qquad \text{if } p \text{ is the lowest strike price}$$

$$= D * \alpha * (1/p_0 - 1/p) \qquad \text{otherwise}$$

Step 2: Denote $C_i(p)$ as the contract amount for player i at strike price p. Base on the allocation scheme, we have

Scheme: *Proportional*

$$C_i(p) = C_T(p) * S_i / \sum_{i=1}^{n} S_i$$

Scheme: *Shaved*

1. Determine the supplier k – last supplier requires contracting.

$$k = \min_{j \le n} \left(\sum_{i=1}^{j} i * (S_i - S_{i+1}) - C_T(p) \ge 0 \right)$$

2. Evaluate the amount of contract still required after "shaving" from the first $k-1$ suppliers.

$$R(p) = C_T(p) - \sum_{i=1}^{k-1} i * (S_i - S_{i+1})$$

3. Determine the amount of contract for each supplier.

$$C_i(p) = \sum_{j=i}^{k-1} (S_j - S_{j+1}) + R(p)/k \qquad \text{if } i \leq k$$

$$= 0 \qquad \text{otherwise}$$

Scheme: *Economical*

1. Sort all resources based on increasing marginal cost. Denote the sorted resources by R_i, $i = 1,\ldots,m$.

2. Determine the marginal resource k for the current contract amount.

$$k = \min_{j \leq m} \left(\sum_{i=1}^{j} Ri - C_T(p) \geq 0\right)$$

3. $R_1,\ldots,R_{k-1}$ are under contract and portion of the resource R_k

$$C_T(p) - \sum_{i}^{k-1} Ri$$

will also be under contract.

Step 3: Set p equals to the next higher strike price and net out the resources already under contract for allocation schemes *shaved* and *economical*. Repeat Step 1 until all the strike prices are exhausted.

D
PORTFOLIO PRICING AND ENERGY COSTS

This appendix documents the calculations for computing the portfolio prices and energy costs cited in Table 3-2.

Sets

Our calculations occur over several dimensions, namely the load and price duration curves, the portfolios, and the contracts. Thus we define the sets in Table D-1.

Table D-1
Set Descriptions

Set	Description
Durations	Indicates the points in the load and price duration curves.
Portfolios	Indicates the portfolios from P0 to P5.
Contracts	Indicates the contract types, which vary by strike price.

Input Data

To calculate the values of the portfolios, we begin with knowledge of the contract portfolios and the simulated prices given the presence of these contracts and the various points in the load duration curve. Thus is simulation used to convert the load duration curve into a collection of price duration curves, one for each portfolio and one for the ACAP market. Table D-2 contains the names of these input data parameters and their descriptions.

Table D-2
Input Parameter Descriptions

Parameter	Description
strike_price(c)	Strike price for contract of type c.
contract_qty(p,c)	Quantity of energy under contract type c in portfolio p.
load(d)	Quantity of demand for load duration point d.
mcp(p,d)	Simulated market-clearing price, given portfolio p, for energy price duration point d.
mcp('ACAP',d)	Simulated market-clearing price, for capacity price duration point d.
prob(d)	Marginal probability for duration point d. Applies to load and price duration curves.

Derived Values

We now derive the expected energy costs to consumers, conditional on the presence of each portfolio. To do this, we first describe the derived parameters as in Table D-3.

Table D-3
Derived Parameter Descriptions

Parameter	Description
incr_contract_qty(p,c)	Incremental contract quantity for contract c in portfolio p when compared to portfolio p-1.
exp_marginal_opp_cost(p,c)	Marginal opportunity cost of entering contract c in portfolio p, given portfolio p-1.
exp_incr_portfolio_cost(p)	Incremental cost of portfolio p, compared to portfolio p-1.
exp_direct_energy_cost(p)	Expected energy payments for consumers, given portfolio p.
exp_side_pmt(p)	Expected side payment from suppliers to consumers as a result of called options, given portfolio p.
exp_energy_cost(p)	Total energy costs to consumers, given portfolio p. This accounts for direct energy costs and side payments.
exp_portfolio_cost(p)	Expected cost to purchase portfolio p.
exp_ACAP_cost	Expected cost to purchase ACAP contracts.

We define the first few parameters in Table D-4 since their meaning is clear from the equations. Note that exp_incr_portfolio_cost(p) is the cost of purchasing portfolio p, given that portfolio p-1 is already in place. The incremental cost of Portfolio 0 is zero, because it has no contracts. So, the incremental cost of Portfolio 1 is the same as the cost of that portfolio. Subsequent portfolio costs benefit from the presence of earlier ones, because the spot energy price is driven down as more contracts are transacted. This causes the opportunity cost for a supplier to likewise go down.

Table D-4
Intermediate Derived Parameter Definitions

Parameter	Definition
incr_contract_qty(p,c)	contract_qty(p,c) – contract_qty(p-1,c)
exp_marginal_opp_cost(p,c)	SUM(d in Durations, MAX(mcp(p-1,d) – strike_price(c), 0) * prob(d))
exp_incr_portfolio_cost(p)	SUM(c in Contracts, exp_marginal_opp_cost(p,c) * incr_contract_qty(p,c))
exp_direct_energy_cost(p)	SUM(d in Duration, mcp(p,d) * load(d) * prob(d))
exp_side_pmt(p)	SUM((d in Duration, c in Contracts), MAX(mcp(p,d) – strike_price(c), 0) * contract_qty(c) * prob(d))

We define the expected direct costs of energy in terms of prices, loads, and probabilities. The expected side payment depends on the market-clearing price being above the strike price as the condition for options to be called. So this difference is multiplied by the contract quantity and the marginal probability that the market-clearing price is observed.

In Table D-5, we define the expected cost of each portfolio, using an incremental approach to transactions. The expected energy cost is the direct payout for energy minus the payback from options calls.

Table D-5
Final Parameter Definitions

Parameter	Definition
exp_portfolio_cost(p)	SUM(pp in Portfolios | (pp <= p), exp_incr_portfolio_cost(pp))
exp_energy_cost(p)	exp_direct_energy_cost(p) – exp_side_pmt(p)

The cost of the ACAP contracts are priced as having no impact on energy costs, so the incremental transaction approach would have no effect. Thus, the ACAP contracts are priced according to the simulation of the pure ACAP market, 'ACAP', where the marginal cost of capacity is zero.

Table D-6
Final Parameter Definitions

Parameter	Definition
exp_ACAP_cost	SUM(d in Duration, mcp('ACAP',d) * load(d) * prob(d))

Summary

The key capacity contract values listed in Table 3-2 are the expected costs for forward contracts for Portfolio 5, exp_portfolio_cost('P5'), and for ACAP, exp_ACAP_cost. The key energy cost values are the expected energy cost under Portfolio 5, exp_energy_cost('P5'), and under Portfolio 0, exp_energy_cost('P0'). The latter value is coupled with the cost of ACAP contracts, because they have no impact on energy prices.

E

CA-ISO FILING ON ACAP

The following text, taken verbatim from the CAISO May 1 Filing [6], is provided background for defining the structure and issues of surrounding ACAP as an element of market design. Most text is easily identifiable from section and paragraph numbers. Some parts have the text *[snip]* added to remind the reader that a large section of text has been skipped. Please refer to the original reference for those portions.

Available Capacity (ACAP) Obligation on Load Serving Entities. The main purpose of the ACAP obligation is to enable the ISO to verify in advance that adequate capacity is available on a daily basis to meet system load and reserve requirements. Thus, the ISO believes that the proposed ACAP Obligation is essential to the ISO's core function – that of providing reliable transmission service. Under Assembly Bill 1890 (AB 1890), the ISO is required to ensure efficient use and reliable operation of the transmission grid consistent with the achievement of planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council (WSCC). The ACAP proposal is consistent with, and supports, that statutory requirement. Specifically, as proposed, the ACAP Obligation will support reliable system operations by requiring LSEs to procure, in a forward-market timeframe, resources sufficient to satisfy the ISO's peak daily operating requirements. Moreover, by requiring that such ACAP resources are made available to the ISO in the day-ahead market, the ISO can satisfy its objective of moving operating decisions from real time into the forward market – further supporting stable and reliable operations.

Recognizing that ACAP is a new element of the California energy market, and that it places new responsibilities and requirements on certain entities, the ISO proposes to transition, over a four-year period, to full ACAP implementation. That consideration notwithstanding, it is imperative that all affected parties begin immediately the substantial task of developing the operational, market, regulatory, and information-based systems necessary to implement the ACAP requirement.

It is important to note that the ACAP Obligation is probably the one element of the proposal for which the roles of state entities and policy makers are most important. Specifically, the rules and practices under which the investor-owned utilities (IOUs) – the largest load-serving entities in California – procure ACAP and the rules for their recovery of associated costs are regulated by the CPUC. In addition, the California Power Authority will likely have a significant role in procuring resources (e.g., generating capacity, forward contracts, and demand-side programs) that meet some portion of the ACAP obligations of California load serving entities. In addition, the power contracts negotiated by the state early in 2001 and currently administered by CERS will continue to comprise a significant share of California's supply. Finally, the question of long-term supply adequacy is a matter for state policy that must engage all policy makers and entities concerned with the functioning of the energy market. Thus, while it is important for the ISO's performance of its core functions to define and verify compliance with the ACAP obligation, the ACAP Obligation alone is not sufficient to ensure adequate supply capacity for California, neither in the long term nor the near term. Supply adequacy is a problem that extends beyond the ISO and depends on effective state policy and on the actions of these other entities.

Summary of ACAP Proposal

The ISO proposes to require each LSE in the ISO Control Area to identify, on a month-ahead basis, the resources they will make available to serve their forecast load for a given month, plus a reasonable reserve margin. The ISO proposes to base such reserve requirements on the established Western Systems Coordinating Council (WSCC) Minimum Operating Reserve Criteria (MORC), but then translate those daily operating requirements into a monthly requirement. LSEs and the ACAP suppliers will then have an obligation to schedule or bid the ACAP capacity into the ISO's day-ahead market. LSEs and ACAP suppliers that fail to satisfy the ISO's monthly and daily requirements will face penalties; penalties set at level necessary to provide incentives for such entities to continually satisfy the ISO's operating requirements. The ISO thus believes that, through its ACAP proposal, system security will be enhanced because sufficient resources will have been committed to serve forecast load and satisfy the ISO's peak load operating reserve requirements. Moreover, satisfaction of these requirements will allow the ISO's real-time market to become a true imbalance market; a market that adjusts for unforeseen outages or demand increases and whose purpose is not to serve large quantities of unscheduled demand.

As detailed further below, the ISO's proposal provides that each LSE's ACAP obligation will be calculated on a monthly basis as a fixed margin above the next month's forecast peak load. LSEs will be required to meet this obligation for all hours that have a significant probability of being the peak hour (most likely the three or four hours across the monthly peak). The obligation may be met by a combination of own generation, firm energy contracts (including contracts obtained by the State on behalf of consumers served by the IOUs), capacity contracts, and physical demand management (as opposed to financial arbitrage between the forward and real-time markets). Prior to the start of each month, the LSE will demonstrate to the ISO that it has secured adequate capacity for the coming month and will be required to identify the relevant "ACAP resources" and associated MW quantities.[7] The LSE will be assessed a penalty for any shortfall.

As the title "Available Capacity" suggests, the ACAP obligation differs from the "Installed Capacity" or ICAP obligation common to the eastern ISOs by virtue of the ACAP's availability requirement. This means that a resource designated as an ACAP resource by an LSE must be fully available to the ISO (for the amount of contracted capacity) via a combination of firm forward energy schedules, bids to participate in unit commitment, supply ancillary services and energy markets, and must respond to ISO dispatch instructions. In the event of a plant outage or derating other than planned maintenance, the supplier would be responsible for providing a substitute resource or paying for replacement energy, would be charged the ACAP shortfall penalty and, if the supplier does not report the outage to the ISO in a timely manner, would be assessed penalties for failing to follow dispatch instructions.

[7] The ISO expects that LSEs would procure portions of their ACAP obligations on different time horizons, such as up to 90 percent on an annual basis, 5 percent seasonally, and 5 percent monthly. However, at least with respect to the IOUs, this matter is appropriately and best addressed in the CPUC's procurement rulemaking.

It is important to clarify that this does not necessarily mean that the supplier has to physically withhold another resource as back up or insurance against an outage. If the back-up resource is bid into the real-time market (BEEP stack), even if it is dispatched for imbalance energy, as long as the amount (MW) bid into the BEEP stack (at or below prevailing market-wide bid caps) equals or exceeds the (forced out) capacity of the ACAP resource, the real-time ACAP unavailability penalty would be waived. Moreover, the ISO's proposed real-time uninstructed deviation penalties would be waived if the outage information is provided to the ISO within 30 minutes. When the DEC instruction is issued to the forced out resource, there would be a charge equal to the MCP. However, if the bid in the BEEP stack from the back-up resource is below the MCP, the other resource would collect the MCP for at least the same amount of MW or more. This means the ACAP provider would not incur any additional cost than the alternative where the other resource had been kept on standby and started up only upon the forced outage of the ACAP resource. In fact, by bidding the other resource in the BEEP stack, the generation owner collects additional revenue as long as the ACAP resource is available (a much more profitable outcome for the generation owner than simply keeping the other unit on standby). If the real-time bid from the other unit reflects that unit's operating cost and is higher than the MCP, the generation owner should be satisfied with the ISO providing the replacement energy from a cheaper unit and charging the corresponding MCP.

In summary, the ISO will verify each LSE's compliance with the ACAP obligation on a monthly basis based on its demonstration of adequate contracts and designation of specific resources, and then will verify compliance for designated ACAP resources on a daily basis based on their availability.

F
FERC RULING ON ACAP

The following text, taken verbatim from the June 17, 2000 FERC Ruling [7], is provided background for defining the structure and issues of surrounding ACAP as an element of market design. Most text is easily identifiable from section and paragraph numbers. Some parts have the text *[snip]* added to remind the reader that a large section of text has been skipped. Please refer to the original reference for those portions.

The CAISO Proposal

15. The CAISO states that it recognizes that the current congestion management system is "severely flawed" and that MD02 is intended to provide for more stable operations through the promotion of day-ahead scheduling, commitment and contracting. Furthermore, the CAISO intends that its proposals will increase operational and price transparency through accurate modeling of the transmission system to reveal true and accurate price differences on the system. The May 1 Filing has the following principal elements:

[snip]

(H) An available capacity (ACAP) requirement to allow the CAISO to verify that load-serving entities are making the necessary advance arrangements to ensure that adequate generating capacity is available to meet system load and reserve requirements. The CAISO proposes that the resources identified by load-serving entities to satisfy this requirement must be made available to the CAISO in the day-ahead market. Furthermore, the CAISO proposes that the ACAP requirement be phased in over a four-year period to give load-serving entities sufficient time to acquire the necessary portfolio of resources.

16. In the May 1 Filing, the CAISO proposes to implement its plan in three discrete phases.[8] Phase one includes design elements that the CAISO proposes to be implemented on October 1, 2002, the day following the end of the current mitigation measures, except for local market power mitigation, which the CAISO proposes be given a July 1, 2002 effective date. The CAISO contends that the phase one changes are necessary to prevent physical and economic withholding from the market and thus are appropriate to replace the existing mitigation measures and to be used for the long-term.

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[8] On June 17,2002, the CAISO submitted proposed tariff language that primarily reflects the phase two and phase three MD02 market design elements (June 17 Filing). In that filing, the CAISO proposes to further delay the implementation of its ACAP proposal from Fall 2003 until Winter 2004. While we take note of specific statements in the June 17 Filing, as we state infra, that submittal will be the subject of a separate Commission order to be issued at a later date.

[snip]

45. As we noted earlier, the West-wide mitigation was intended to be a short-term measure to be replaced by a comprehensive forward looking market design. The CAISO states that its ACAP market proposal is designed to encourage proper long-term pricing signals to complement the accompanying market power mitigation measures. The purpose of ACAP is to provide incentives for long-term resource adequacy. If the spot market is the sole backstop for resource adequacy then market power mitigation rules must be relaxed to allow for prices that properly signal scarcity and allow greater opportunity for generators to recover their total costs.

[snip]

63. The Market Surveillance Committee believes that the local market power of some suppliers was among the greatest structural problems in the California market.[9] The existence of transmission constraints within the CAISO system remains a structural problem that continues to give suppliers local market power. The Commission has adopted and approved measures to mitigate this problem for all East Coast ISOs. The Market Surveillance Committee believes it is important for California to have comparable measures. The Market Surveillance Committee strongly agrees with the CAISO that an ACAP market is not practical to implement over the short-term. Though the Committee believes that ACAP may best address market power, they note that in the short run, AMP is the best solution. According to the Market Surveillance Committee, even though the CAISO has a number of generating units under Reliability-Must-Run (RMR) contracts that it can call to mitigate local market power, system conditions often occur when generating units other than RMR units are able to exercise local market power. Consequently, the Market Surveillance Committee strongly supports the implementation of an automatic mitigation procedure on all generating units that possess local market power according to a clearly articulated criterion.

[snip]

G. Long-Term Elements Set for Technical Conference

1. Available Capacity (ACAP) Requirement

119. As stated above, the CAISO proposes an ACAP requirement to allow it to verify that load-serving entities are making the necessary advance arrangements to ensure that adequate generating capacity is available to meet system load and reserve requirements. The Commission believes that a requirement to assure long-term adequate resources is needed because most resources take years to develop and spot market prices alone will not signal the need to begin development of new resources in time to avert a shortage. Moreover, spot market prices that are subject to mitigation measures may not produce an adequate level of infrastructure investment even after a shortage occurs.

[9] The Market Surveillance Committee includes asymmetric treatment of final consumers and producers of electricity, and the lack of sufficient forward contracting by load-serving entities in its list of the three main structural problems in the California markets (Market Surveillance Committee at 2).

120. While the Commission believes that an ACAP-like requirement has potential to address resource adequacy, we note that the CAISO is not prepared to implement an ACAP, or any alternative proposal, until January 2004.[10] Such a delay, in our view, impedes market development and may undermine other attempts to improve market rules. Consequently, the Commission finds that a resource adequacy proposal is a fundamental pillar of any workable market design. Therefore, in light of the CAISO commitment to the development of a long-term permanent solution to resource adequacy and the need for stakeholder involvement in this development process, we will set the proposed ACAP requirement for expedited development at the technical conference we will direct staff to convene. As stated earlier, this issue must be addressed quickly and comprehensively. Swift resolution of this issue will assure resource adequacy, which is critical for market stability.

[10] See June 17 Transmittal Letter at 30.

PUBLIC INTEREST ENERGY RESEARCH
"Research Powers the Future"

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